# 1. ABOUT THE MANUAL

## 1.1 Introduction

### 1.1.1 Objectives

The objective with this manual is to help reservoir engineers to plan, define, initiate, follow up and quality-control fluid samples and PVT analyses. In addition, guidelines are given to assemble, compare, and apply PVT data for input to reservoir calculations, e.g. fluid characterization, "quick-look" material balance calculations, black-oil and compositional reservoir simulation, well test analysis, process simulation, etc.

### 1.1.2 How to Use the Manual

Engineers with little or no experience in fluid sampling, PVT analysis, and equation of state (EOS) simulation, should read this manual carefully. The main body of the manual may not include all the general background material required. However, selected PVT references are enclosed in the manual.

The experienced engineer familiar with PVT may use this manual as a reference on the following subjects:

**Fluid Sampling and Laboratory Analyses**

Chapters 2 and 3 assist in how to design, initiate, follow up, and quality- control fluid samples and PVT analysis of laboratory data. Chapter 3 summarizes the sampling procedures used to collect fluids and the experimental methods used to measure fluid properties. Procedures and recommendations related to initiating fluid sampling and PVT analyses are presented in Chapter 2. We urge the engineers to use the order forms included for fluid sampling, compositional analyses, and PVT studies.

**PVT Requirements/Oil and Gas Correlations**

Chapter 4 summarizes PVT requirements and correlations. This chapter is useful as a reference for engineers working with prospect evaluation, where measured PVT data are often unavailable and must be calculated from correlations. Engineers who already use certain PVT correlations (e.g. on a spreadsheet) may find useful the discussions related to each correlation.

**Example Calculations: Correlations and EOS Simulation**

Perhaps the most important contribution of this manual are the example calculations in Chapter 5. The examples are based on several different fluid systems from the Visund field: Brent North II oil, gas and water samples, Statfjord undersaturated oil samples, and Lunde condensate samples.

Oil and gas PVT properties for Brent North are calculated from correlations in

Sections 5.2 and 5.3. Section 5.4 gives a short discussion of the steps involved in using an equation of state model, and how the program PVTx (or a similar program) handles the various steps in an EOS characterization. Example calculations using an EOS model are presented in Sections 5.5-5.8, including PVTx input files. These examples include EOS predictions, $C_{N+}$ characterization using TBP data, regression, pseudoization, generation of modified BO parameters, slim-tube simulations, and compositional gradients.

## 1.2 Other Norsk Hydro Manuals Related to PVT

### 1.2.1 Well Test Manual

Production Technology F&T has generated an internal manual on well test planning and operations. The manual includes procedures and description of tools used for fluid sampling, and this manual is recommended for engineers ordering and planning fluid sampling.

### 1.2.2 Reservoir Simulation Manual

Reservoir Technology F&T has recently completed a reservoir simulation manual including a short description of the PVT input required for Eclipse 100.

The ECLIPSE 200 options, e.g. Solvent- (Todd-Longstaff), GI-, and Polymer-options have recently been described in a report which also specifies the required PVT input.

### 1.2.3 Manual for Laboratory PVT Analysis

A manual for laboratory PVT analysis exists at the Fluid Laboratory Department at the U&P Research Centre in Bergen. This manual gives detailed procedures for performing various PVT experiments and compositional analyses. Standard methods for measuring physical properties, and the accuracy of measured data are also included.

## 1.3 PVT Manual Revisions

This manual is not yet fully complete. Special PVT experiments like swelling, multi-contact gas injection and slim-tube experiments are yet to be described.

A library of programs related to fluid analysis and EOS simulation will later be organized and described in this manual. Also, as new methods and tools become available, descriptions of these will be added to the manual.

# 2. INITIATING A PVT STUDY

## 2.1 Ordering a PVT Study

### 2.1.1 What PVT Sampling Do I Need?

This section summarizes which fluid sampling methods can be recommended for a given type of reservoir fluid. For more details see Section 3.2 and Tables 3.1 and 3.2. Composition and physical properties typical for each type of reservoir fluid are presented in Table 3.3.

The following table summarizes reservoir fluid types, the approximate range of GOR for each fluid type, and the recommended sampling method(s) for each fluid type.

| Reservoir Fluid Type | GOR $Sm^3/Sm^3$ | Recommended Sampling Method[a] |
|---|---|---|
| Black Oil | <150 | BHS, SEP, WHS[b] |
| Volatile Oil | >150 | BHS, SEP, WHS[b] |
| Near-Critical Oil | 400-600 | SEP |
| Rich Gas Condensate | <1000 | SEP |
| Gas Condensate | >2000 | SEP, IKS[c] |
| Wet Gas | >10000 | SEP, IKS[c] |
| Dry Gas | >100000 | SEP, IKS[c] |

Notes

a. BHS : Bottom Hole Sampling
WHS : Well Head Sampling
SEP : Separator sampling
IKS : Isokinetic Sampling

b. Recommended sampling method for a reservoir oil depends primarily on reservoir pressure, $p_R$, relative to saturation pressure, $p_{sat}$; for more details see Table 3.2 and Section 3.2.
In general, the following recommendations are made:

$p_R=p_{sat}$: SEP; $p_R>p_{sat}$: BHS; $p_R>>p_{sat}$: WHS

WHS sampling requires single-phase fluid at the wellhead.

c. Isokinetic sampling should be considered when significant carry-over of separator liquid into the gas stream is suspected (lean gas condensates at high rates).

### 2.1.2 Summary of Available PVT Studies

This section summarizes the standard PVT studies that are available at PVT laboratories (Norsk Hydro in-house and commercial labs).

An overview of the standard PVT experiments is given on the following pages. The summary tables focus on the objectives of each experiment, measured and calculated data resulting from the experiment (non-standard data, with added cost, are noted in brackets []), and finally, the cost and time required to perform an experiment are given. For a detailed description of each experiment, see Section 3.4.

### 2.1.3 What PVT Studies Do I Need?

This section defines the standard PVT experiments that are recommended for a given type of reservoir fluid. Which experiment to perform is to some extent dependent on the development phase of the well/field. When the well is an appraisal well, the fluid sampling and PVT program may be less extensive.

| **Reservoir Fluid Type** | **BHS/SEP Comp.** | **TBP** | **DLE** | **CCE** | **CVD** | **SST** | **MST** |
|---|---|---|---|---|---|---|---|
| Black Oil | • | ❍ | • | • | N | • | • |
| Volatile Oil | • | ❍ | • | • | N | • | • |
| Near-Critical Oil | • | ❍ | ❍ | • | • | • | • |
| Rich Gas Cond. | • | ❍ | N | • | • | • | ❍ |
| Gas Condensate | • | ❍ | N | • | • | • | ❍ |
| Wet Gas | • | ❍ | N | • | N | • | N |
| Dry Gas | • | N | N | • | N | • | N |
| Water | ❍ | N | N | ❍ | N | ❍ | N |

Note: • standard experiment ❍ can be performed N not performed

| **Bottomhole Sample Composition** | |
|---|---|
| Objectives | Obtain molar composition of a reservoir fluid collected by bottomhole sampling. See also single-stage separator test. |
| Measured Data | $z_i$, $(x_i)_{sc}$, $(y_i)_{sc}$, GOR, $(\rho_o)_{sc}$, $\gamma_g$, $M_g$, $M_o$, $M_{C6\text{-}C10+}$, $\gamma_{C6\text{-}C10+}$ |
| Consistency Checks | · Bubblepoint of BHS at "rig" temperature.<br>· Compare bubblepoints of BH samples taken at same time.<br>· Compare bubblepoint at $T_R$ with bottomhole flowing pressure(s) before/during sampling.<br>· Watson characterization factor for $C_{7+}$. |
| Cost | 7 kNOK |
| Duration | 1 day |

| **Recombined Separator Sample Composition** | |
|---|---|
| Objectives | Obtain the recombined molar composition of a reservoir fluid collected by separator sampling. |
| Measured Data | $z_i$, $(x_i)_{sp}$, $(y_i)_{sp}$, GOR $(R_{sp})$, $\rho_o$, $\gamma_g$, $M_g$, $M_o$, $M_{C6\text{-}C10+}$, $\gamma_{C6\text{-}C10+}$ |
| Consistency Checks | · Hoffman et al. (Kp-F) plot.<br>· Quantify effect of (1) separator GOR, (2) $M_{7+}$, and (3) liquid carryover on recombined composition.<br>· Watson characterization factor for $C_{7+}$ (from $M_{7+}$ and $\gamma_{7+}$). |
| Cost | 30 kNOK |
| Duration | 3 days |

| **True Boiling Point Analyses (TBP)** | |
|---|---|
| Objectives | Obtain mole, mass and volume fractions and physical properties for distillation cuts of a stock-tank oil or condensate. |
| Measured Data | $x_i$, $w_i$, $V_i$, $M_i$, $\gamma_i$ [PNA distribution][a] |
| Consistency Check | · Fit weight (or mole) fraction and molecular weight data using gamma distribution function (CHAR program). Eventually adjust residue molecular weight.<br>· Watson characterization factor for $C_{7+}$ (from $M_{7+}$ and $\gamma_{7+}$). |
| Cost | 60 kNOK (to $C_{20+}$) |
| Duration | 10 days |

a. An extended TBP analysis is sometimes requested by the process department. This type of analysis requires a minimum 5 liter sample. Additional data for each distillation cut include: viscosity, pour point, freezing point, refractive index, and enthalpy.

| **Single-Stage Separator Test (SST)** | |
|---|---|
| Objectives | Determine recombined or bottomhole reservoir fluid composition.<br>May also be used in converting DLE data from residual to stock-tank basis (not usual). |
| Measured Data | $B_o$, $R_s$, $B_g$, $\rho_o$, $Z_g$, $M_g$, $M_o$, $z_i$, $(y_i)_{sc}$, $(x_i)_{sc}$ |
| Consistency Check | · Compare wellstream composition with other wellstream compositions based on separator samples.<br>· Watson characterization factor for $C_{7+}$ (from $M_{7+}$ and $\gamma_{7+}$). |
| Cost | 15 kNOK |
| Duration | 1-2 days |

| **Multistage Separator Test (MST)** | |
|---|---|
| Objectives | Converting DLE from residual basis to stock-tank basis.<br>Also (historically) to determine the separator conditions that maximize stock-tank oil production (now obsolete; not recommended for this use). |
| Measured Data | $B_o$, $R_s$, $B_g$, $\rho_o$, $Z_g$, $M_g$, $M_o$, $y_i$ $[(x_i)_{\text{each stage}}]$ |
| Consistency Check | · Calculate reservoir fluid density using FVF, GOR, and specific gravity data; i.e. bulk material balance.<br>· Component material balance when both oil and gas compositions are measured.<br>· Watson characterization factor for $C_{7+}$ (from $M_{7+}$ and $\gamma_{7+}$). |
| Cost | 20-30 kNOK |
| Duration | 5 days |

| **Constant Volume Depletion (CVD):** | |
|---|---|
| Objectives | Provides volumetric and compositional data for gas condensate and volatile oil reservoirs producing by pressure depletion. |
| Measured Data | $p_{sat}$, $V_{ro}$, $G_p$, $Z_g$, $\mu_g$, $y_i$, $M_{gN+}$, $\gamma_{gN+}$ $[(x_i)_{last\ stage}]$ |
| Consistency Check | . Component and bulk material balance (see Whitson and Torp, 1983).<br>. K-value (Kp-F) plots based on material balance results.<br>. Compare relative oil volume data with CCE relative oil volume data.<br>. Plot data versus pressure to identify erroneous data (data not following physically acceptable trends). |
| Cost | 65 kNOK |
| Duration | 10 days |

| **Constant Composition Expansions (CCE) - Gas Condensates** | |
|---|---|
| Objectives | Determine dewpoint pressure and volumetric properties at reservoir temperature (and eventually at other lower temperatures). |
| Measured Data | $p_d$, $V_{ro}$, $V_{rt}$, $Z_g$, $\mu_g$, $B_{gw}$ |
| Consistency Check | . Compare reported Z-factors with values calculated from composition and the Standing-Katz chart ($p \geq p_d$).<br>. Plot data versus pressure to identify erroneous data (data not following physically acceptable trends). |
| Cost | 20 kNOK |
| Duration | 3 days |

| **Constant Composition Expansions (CCE) - Oils** | |
|---|---|
| Objectives | Determine bubblepoint pressure and volumetric properties at reservoir temperature and eventually at lower temperature. |
| Measured Data | $p_b$, $V_{rt}$, $\rho_o$, $c_o$, Y [$V_{ro}$, $\mu_o$] |
| Consistency Check | · Make undersaturated oil relative volume plot to determine compressibility relation $c_o$=A/p; A=constant.<br>· Plot data versus pressure to identify erroneous data (data not following physically acceptable trends). |
| Cost | 10 kNOK ($T_R$) ; 5 kNOK ($T_{sc}$) |
| Duration | 1 days |

| **Differential Liberation Expansion (DLE):** | |
|---|---|
| Objectives | Approximate the depletion process of a reservoir oil, and thereby provide suitable PVT data for calculating depletion reservoir performance. |
| Measured Data | $B_{od}$, $R_{sd}$, $B_{gw}$, $\rho_o$, $Z_g$, $\mu_g$, $\gamma_g$, $\rho_g$ [$\mu_o$, $y_i$, $x_i$][a] |
| Consistency Check | · Component and bulk material balance.<br>· Compare reported Z-factors with values calculated from composition and the Standing-Katz chart ($p \geq p_d$).<br>· Plot data versus pressure to identify erroneous data (data not following physically acceptable trends).<br>· Plot differential $B_{od}$ and $R_{sd}$ data relative to bubblepoint oil volume instead of residual oil volume using the variables $B_{od}/B_{odb}$ and $(R_{sdb}-R_{sd})/B_{odb}$. |
| Cost | 40 kNOK |
| Duration | 8 days |

[a] Oil viscosity should always be ordered. Equilibrium gas compositions (through $C_{7+}$ or $C_{10+}$) should also be ordered for oils with a solution GOR>100-150 $Sm^3/Sm^3$.

### 2.1.4 Contact & Cooperation with Other Engineering Groups

When ordering PVT sampling and analyses, Reservoir Technology R&T cooperates with Production Technology and Process Technology to collect samples for analyses performed by these departments.

Fluid analyses performed or purchased by other departments may include:

**Production Technology:**

- Wax Point, Hydrate and Asphaltene Analyses (large separator samples required)
- Formation Water/Brine Analyses

**Process Technology:**

- TBP-Analyses with high-temperature cuts (minimum 5 liter sample)
- CCEs specified at temperatures lower than reservoir temperature for process simulation (also ordered by Reservoir Technology and used by Production Technology in well hydraulics)

**Production Geology:**

- Formation water/brine resistivity for petrophysical analyses
- Geochemical analyses of collected fluids (natural tracers, Strontium-isotope analyses, etc.)

Most of these special studies require large samples of separator or tank oil.

Design and planning of fluid sampling in cooperation with the department responsible for well testing is important. Well test design and sample preparations that may affect sampling should be discussed and included in plans before sampling is performed.

Handling and transportation of the sample bottles after sampling should also be discussed. Wax-, hydrate- and asphaltene analyses may be adversely affected if the temperature of the sample bottles drop below about 30$^{o}$C (even for a short period).

### 2.1.5 Forms for Ordering Standard PVT Studies

Special forms have been generated for planning and ordering PVT samples and analyses. Use of these forms (which are divided into three parts) is recommended. The three parts are:

**Part I** describes fluid sampling (formations, conditions, methods) and quality control of the samples collected.

**Part II** describes compositional analyses of the samples collected. Some guidelines for quality control of compositional analyses are also discussed.
**Part III** specifies which PVT experiments should be performed, and recommended design of the experiments (number of pressure steps, which properties to measure, etc.).

The laboratory chosen to perform the PVT analyses should present a quality control of Part I before continuing to Parts II and III. This will ensure that compositional analyses and PVT experiments to be performed are based on the sample(s) considered most representative for the actual formation(s). The purchaser should also require a preliminary report of Part II results before continuing with Part III.

It is also important that the reservoir-, production-, and process engineers all take part in filling out the forms, and eventually approve the plans for sampling and analyses by signing the forms (page 1).

### 2.1.6 Ordering Special PVT Studies

Special PVT studies like Swelling Experiments, Multi-Contact Gas Injection Experiments and Slimtube Experiments should be designed and ordered in cooperation with PVT specialists. These experiments are considered important for evaluation of EOR methods such as miscible and immiscible gas injection, and WAG (water-alternating gas).

### 2.1.7 Following Up an Ongoing PVT Study

The order form discussed in Section 2.1.5 includes a few hints regarding follow up of an ongoing PVT study. Some suggestions are:

- Stay in contact with the PVT laboratory during *all* phases of the study.

- Remind the PVT laboratory to respond back after quality control of sample bottles, to ensure that the PVT study will be continued based on the best samples.

- Remind the PVT laboratory to respond back after the compositional analyses have been performed and quality checked. The PVT laboratory should ask for your permission before they initiate the PVT experiments (i.e. they should not start before the compositional analyses have been approved).

- Ask the PVT laboratory for all measured data; sometimes even "raw-data" may be needed to check questionable reported data.

### 2.2.2 Sampling Companies

Companies dealing with fluid sampling in the North Sea are listed below:

| Company | Sampling Methods | Comments |
|---|---|---|
| Schlumberger | RFT, MDT, BHS, SEP | Used most for RFT, MDT |
| ELS | BHS, RFT | Single phase BHS |
| Western Atlas | RFT, BHS, SEP | Associated CoreLab |
| Petrotech | BHS, SEP, IKS | Single phase BHS |
| Altinex, NH | BHS | Petrotech is operator |
| Exal | BHS, SEP | ELS operator in Norway |
| Oilphase | BHS | Single phase BHS<br>(Petrotech is operator) |

### 2.2.3 PVT Laboratories (external)

| Company | Available PVT Experiments | Comments |
|---|---|---|
| GECO Prakla | Standard PVT | ISO 9002 certification ongoing |
| Core Laboratories Aberdeen | Standard PVT<br>Swelling<br>Slimtube<br>Wax and Asphaltene | ISO 9002 certified |
| EXPRO | Standard PVT<br>Swelling<br>Slimtube<br>Wax and Asphaltene | ISO 9002 certified in 1994 |

## 2.3 NOMENCLATURE

**Abbreviations**

| | |
|---|---|
| BHS | Bottomhole Sampling |
| BO | Black Oil |
| CCE | Constant Compositional Experiment |
| CVD | Constant Volume Depletion |
| DLE | Differential Liberation Experiment |
| FVF | Formation volume factor |
| GC | Gas Chromatography |
| GOR | Gas-Oil Ratio |
| IKS | Isokinetic Sampling |
| MST | Multistage Separator Test |
| OGR | Oil-Gas Ratio |
| RFT | Repeat Formation Test |
| SEP | Seperator Sample or Sampling |
| SST | Single-stage Seperator Test |
| TBP | True Boiling Point Analysis |
| WHS | Wellhead Sampling |

**Symbols**

| | |
|---|---|
| $B_g$ | Dry Gas FVF from flash, $m^3/Sm^3$ |
| $B_{gd}$ | Dry Gas FVF from DLE, CVD, $m^3/Sm^3$ |
| $B_{gw}$ | Wet Gas FVF, $m^3/Sm^3$ |
| $B_o$ | Oil FVF from seperator flash, $m^3/Sm^3$ |
| $B_{od}$ | Differential oil volume factor from DLE, $m^3$/residual $m^3$ |
| $c_o$ | Isothermal oil compressibility, $bar^{-1}$ |
| $F_i$ | Hoffmann et al. Characterization Factor |
| GOR | Gas Oil Ratio, $Sm^3/Sm^3$ |
| $G_p$ | Cumulative mole percent (wet) gas produced in CVD experiment, relative to initial moles at dewpoint |
| $K_i$ | Equilibrium constant, $y_i/x_i$ |
| $K_w$ | Watson Characterization Factor [$K_w \equiv T_b^{1/3}/\gamma$] |
| $M_g$ | Molecular weight of gas, kg/kmol |
| $M_{gN+}$ | Molecular weight of the $C_{N+}$ fraction in gas, kg/kmol |
| $M_i$ | Molecular weight of component i, kg/kmol |
| $M_o$ | Molecular weight of oil, kg/kmol |
| $p_b$ | Bubblepoint pressure, bar |
| $p_d$ | Dewpoint pressure, bar |
| $p_R$ | Reservoir pressure, bar |
| $p_{sat}$ | Saturation pressure, bar |
| $p_{sp}$ | Separator pressure, bar |
| $R_s$ | Solution GOR from seperator flash, $Sm^3/Sm^3$ |
| $R_{sd}$ | Differential solution GOR from DLE, $Sm^3$/residual $m^3$ |
| $R_{sp}$ | Separator GOR, $Sm^3$/sep.$m^3$ |
| $r_s$ | Solution OGR from seperator flash of a gas condensate ($r_s$=1/GOR), $Sm^3/Sm^3$ |
| $T_R$ | Reservoir temperature, ◦C or K |
| $T_{sp}$ | Seperator temperature, ◦C or K |

| | |
|---|---|
| $V_i$ | Volume fraction of component i at standard conditions |
| $V_{ro}$ | Relative oil volume, relative to either total volume *or* volume at saturation pressure (depends on the laboratory) |
| $V_{rt}$ | Total (gas-plus-oil) volume relative to volume at saturation pressure |
| $w_i$ | Weight fraction |
| $x_i$ | Oil molar composition |
| $x_{ir}$ | Residual oil molar composition |
| Y | Function used in smoothing two-phase (gas-oil) volumetric data below the bubblepoint during a constant compositional experiment |
| $y_i$ | Gas molar composition |
| $z_i$ | Recombined wellstream (reservoir) molar composition |
| $Z_g$ | Deviation or Z-factor for gas |
| $\mu_g$ | Gas viscosity, mPa.s |
| $\mu_m$ | Cell Mixture Viscosity, mPa.s |
| $\mu_o$ | Oil viscosity, mPa.s |
| $\rho_o$ | Oil density, kg/m$^3$ |
| $\sigma_{go}$ | Gas-oil interfacial tension, mN/m |
| $\gamma_g$ | Specific gravity of gas (air=1) |
| $\gamma_{gN+}$ | Specific gravity of the $C_{N+}$ fraction in gas, water=1 |
| $\gamma_i$ | Specific gravity of component i (water=1) |

# 3. FLUID SAMPLING AND ANALYSIS OF LABORATORY DATA

## 3.1 Introduction

### 3.1.1 Important PVT Data

Oil and gas samples are taken to evaluate the properties of produced fluids at reservoir conditions, in the production tubing, and in pipeline transportation. The key PVT (pressure-volume-temperature) properties to be determined for a reservoir fluid include:

- Original reservoir composition(s)
- Saturation pressure at reservoir temperature
- Oil and gas densities
- Oil and gas viscosities
- Gas solubility in reservoir oil
- Liquid (NGL/condensate) content of reservoir gas
- Shrinkage (volume) factors of oil and gas from reservoir to surface conditions
- Equilibrium phase compositions

Standard experimental procedures are used for measuring these properties, including expansion and depletion studies, and multistage separator tests.

Reservoir fluid samples can also be used in gas injection studies, where oil recovery by vaporization, condensation, and developed miscibility are quantified. Slimtube tests and multicontact gas injection PVT studies are typically used for this purpose.

Less traditional PVT analyses include:

- Analysis of produced water, including salinity and brine composition
- Wax and asphaltene analysis
- Hydrates and emulsions

This chapter summarizes the sampling procedures used to collect fluids, and the experimental methods used to measure fluid properties. A summary of PVT data is given in Table 3-1.

## 3.2 Sampling Methods

### 3.2.1 Type of Sampling

The API[1] gives recommended practices for sampling oil and gas wells.

Furthermore, Norsk Hydro has a chapter on Sampling Procedures in their Well Testing Manual[2]. Several sampling methods can be used to collect reservoir fluids, including

- RFT Sampling
- Bottomhole sampling
- Separator sampling
- Wellhead sampling

The choice of method depends primarily on (1) whether the reservoir fluid is an oil or gas, and (2) whether the reservoir fluid is saturated (or nearly saturated) at reservoir conditions. The second condition is determined by whether the well produces single phase fluid into the wellbore at the flowing bottomhole pressure.

Table 3-2 gives a Schlumberger-produced look-up table for determining sample requirements for various situations in the testing of oil and gas condensate reservoirs.

### 3.2.2 Representative Samples

Before field development starts, the primary goal of sampling is to obtain "representative" samples of the fluid or fluids found in the reservoir at initial conditions. It may be difficult to obtain a representative sample because of two-phase flow effects near the wellbore. This occurs when a well is produced with a flowing bottomhole pressures below the saturation pressure of the reservoir fluid(s).[a]

Misleading fluid samples may also be obtained if gas coning or oil coning occurs.

The best (most representative) samples are usually obtained when the reservoir fluid is single phase at the point of sampling, be it bottomhole or at the surface. Even this condition, however, may not ensure representative sampling (see section 3.2.5).

Because reservoir fluid composition can vary areally, between fault blocks, and as a function of depth, we are actually interested in obtaining a sample of reservoir fluid that is representative of the volume being drained by the well during the test.

Unfortunately, the concept of a "representative" sample is usually

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[a] If a significant positive skin effect exists, then the region near the wellbore that actually is below the saturation pressure may be insignificant (i.e. consisting of a volume that will practically not effect produced fluid sampling). The well testing engineer should quantify the pressure drop due to damage skin (if it exists) at the rate when the well experiences the lowest wellbore flowing pressure. In fact, they should provide an adjusted flowing wellbore pressure plot versus time during sampling that shows the effect of positive skin. The adjusted flowing pressure is probably better to use in evaluating if wellbore conditions were in fact condusive to sampling.

> *A sample that correctly reflects the composition of reservoir fluid at the depth or depths being tested.*

If we suspect or know that a sample is not "representative" (according to this definition), then we tend to do nothing with the sample. Or we question the validity of the PVT analysis done on the "unrepresentative" sample, and consequently don't include the measured data when developing our EOS fluid characterization.

In general, we should not use this definition of "representivity." First of all, it is a definition that costs our industry in terms of wasted money and time, and lost opportunity. Some points to keep in mind are:

> Any fluid sample that produces from a reservoir is automatically representative of that reservoir. After all, the sample *is* produced from the reservoir!
>
> The final EOS fluid characterization of the reservoir fluid(s) should be required to match *all* (accurate) PVT measurements of *all* samples produced from the reservoir, independent of whether the samples are representative of insitu compositions.
>
> *Accuracy of PVT Data ≠ Representivity of Sample*
>
> Accurate PVT measurements can be made on *both* representative and unrepresentative samples. Inaccurate PVT measurements can also be made on both types of samples; bad PVT data *should* be ignored.

Furthermore, an EOS fluid characterization is used to predict compositional changes during depletion which represent a much greater variation than the compositional differences shown by "representative" and "unrepresentative" samples.

Another misconception in "representative" fluid sampling of gas condensates is that it is difficult to obtain insitu-representative samples in saturated gas condensate reservoirs (with underlying oil). *The exact opposite is true!* We can readily show that if a gas condensate is initially saturated and in contact with an underlying oil zone, then a near-perfect insitu-representative sample can be obtained (at the gas-oil contact). Independent of whether the reservoir gas and reservoir oil samples collected are insitu-representative.

### 3.2.3 Define the Fluid Type

For a new discovery it is important that the fluid type and saturation conditions can be estimated based on somewhat limited production data. Such data might include producing gas-oil ratio, stock-tank oil and separator gas gravity, reservoir temperature, and initial reservoir pressure. Produced wellstream composition may also be available.

Correlations such as presented by Standing and Glasø (section 4.4) can be used to estimate bubblepoint pressure with an accuracy of 5 to 10%. When composition is available, an equation of state can be used to predict the saturation pressure (bubblepoint or dewpoint) with about the same accuracy. Better predictions can usually be expected for oils, but with accurate composition and $C_{7+}$ properties, dewpoint predictions of gas condensates also can be expected.

Figure 3-1 shows a typical pressure-temperature diagram for a reservoir fluid. The phase envelope defines the locus of bubblepoints and dewpoints joined at the critical point. A reservoir with temperature less than the critical point is defined as an *oil reservoir*. A reservoir with temperature between the critical temperature and the cricondentherm is defined as a *gas condensate reservoir*. If reservoir temperature is higher than the cricondentherm then the reservoir is defined as a *gas reservoir*.

Further qualtitative fluid definitions are sometimes used. For example, oil reservoirs are classified in two categories: *black-oil resevoirs* and *volatile oil reservoirs* (determined according to their initial solution GOR and STO gravity; approximately, black-oil: $R_s$<150 $Sm^3/Sm^3$ and volatile oil: $R_s$>150 $Sm^3/Sm^3$).

Gas reservoirs are sometimes classified as *wet gas reservoirs* (producing some liquid at surface conditions) or *dry gas reservoirs* (neglible surface liquid production). Furthermore, gas condensate reservoirs are sometimes grouped into the categories *lean gas condensate reservoirs* (GOR>2000 $Sm^3/Sm^3$) and *rich gas condensate reservoirs* (GOR<1000 $Sm^3/Sm^3$).

Returning to Figure 3-1, a resevoir fluid is a single phase at conditions outside the phase envelope. Within the phase envelope, two phases (gas and oil) exist. Any time two phases coexist locally (e.g. gas and oil within a pore), each phase separately is in a saturated state; the oil is at its bubblepoint and the gas is at its dewpoint. This fundamental concept is instrumental in understanding reservoir phase behavior.[a]

Initially a reservoir will always be at a pressure and temperature that is one or outside the phase envelope. During production and subsequent pressure reduction in the reservoir, the system may enter the two-phase region.[b]

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[a] Likewise, the concept of saturated phases applies to water and hydrocarbon phases in local equilibrium. For example, in an oil-water system system, *both* phases are saturated - with respect to each other. Even though the oil is highly undersaturated with respect to a gas phase, the oil is still saturated - with respect to water; likewise, water is saturated with components in the oil phase.

[b] After the reservoir enters the two-phase region, differential amounts of reservoir gas and oil are produced, according to relative permeability and viscosity ratios of the two phases. Subsequently, the remaining reservoir fluid does not have the same composition, and its phase envelope will therefore change from the original phase envelope. It is therefore of limited use to design reservoir behavior during depletion based on the original p-T diagram.

In practice there are three types of fluid systems in a given geological formation with vertical hydrodynamic communication. As shown in Figure 3-1, these are:

- Undersaturated System with Uniform Composition

- Saturated System with Uniform Composition

- Saturated and/or Undersaturated System with Compositional Gradient

A primary objective of fluid analyses in new discoveries is to establish the type of fluid system. However, without production from several intervals and/or several wells, it will be difficult to establish the classification with any great certainty.

Ula is an example of an undersaturated oil reservoir with relatively uniform composition. Sleipner is an example of an undersaturated gas condensate reservoir with relatively uniform composition. Troll is a saturated reservoir with fairly uniform composition in the gas cap and in the oil.

Oseberg is an example of a saturated/undersaturated reservoir with significant compositional variation with depth (particularly in the oil). Another exmaple is the Statfjord formation in the Statfjord field.

Eldfisk and Ekofisk fields are examples of undersaturated oil reservoirs with some compositional variation with depth.[3] Interestingly, the variation of composition (bubblepoint) with depth is not the same in the two main geological formations (Ekofisk and Tor).

The Statfjord formation in the Brent field is perhaps the most unusual fluid type.[4] The reservoir is undersaturated throughout, but the composition varies from a somewhat volatile oil at the bottom to a gas condensate at the top. At some depth a transition from bubblepoint to dewpoint occurs - but without a gas-oil contact! The point of transition is marked by a mixture with critical temperature equal to reservoir temperature (at that depth); at the transition, reservoir pressure is higher than the saturation (critical) pressure of the mixture (see Figure 3-1).

### 3.2.4 Conditioning a Well Before Sampling

A well should normally be "conditioned" before sampling, particularly for gas condensate and saturated oil wells. First the well is produced long enough to clean up all chemicals that were used during the well completion. Next, the rate is stepwise decreased until the flowing bottomhole pressure is larger than the estimated saturation pressure (if possible).

The final flow rate must be large enough to maintain a stable producing GOR and wellhead pressure, even if the flowing bottomhole pressure is less than the saturation pressure. Also, the final flow rate should be maintained long enough to ensure that the producing GOR is more-or-less constant.

A constant producing GOR does not necessarily indicate that the produced wellstream is "representative" of the original reservoir fluid. In fact, it may not be possible to obtain a truly representative sample for reservoir oil and gas condensate systems initially in a saturated state.

Sample containers are usually shipped by boat to land, and thereafter by air or ground transport to the PVT laboratory. As requested by the field operator, compositional analysis and standard PVT experiments are performed on the samples at a PVT laboratory.

### 3.2.5 RFT Sampling

Repeat Formation Tester (RFT) sampling (open wellbore sampling) is probably the least accurate of all methods of sampling, mostly because of the limited volume of sampling. However, RFT samples should be valid under the following conditions:

- Undersaturated oil
- High Permeability
- Water-based mud used when drilling

If oil-based mud is used during drilling then the samples can only be used for approximate compositional analysis. The hydrocarbon components found in the oil-based mud must be backed out of (subtracted from) the overall composition.

The greatest advantage of RFT sampling is that the fluid is defined for a precise depth. Many reservoirs exhibit compositional variation with depth. Accurate RFT samples can help establish this variation, typically a task that is very difficult.

### 3.2.6 Bottomhole Sampling

Undersaturated oils are usually sampled with bottomhole containers lowered into the wellbore on a wireline (Figure 3-3, Figure 3-1). The bottomhole sample is taken while the well is flowing at a relatively low rate. The flowing bottomhole pressure should always be higher than the estimated bubblepoint pressure of the reservoir oil.

Bottomhole oil samples can also be taken when a well is shutin. The flowing bottomhole pressure prior to shutin should be higher than the bubblepoint pressure.

The typical procedure for bottomhole sampling includes:

- Install sample container in the production tubing
- Make pressure gradient measurements going into the hole
- Position sampler at the specified depth
- Produce the well at a low, stable rate (following conditioning)

- Sample during the flow test (dynamic sample) or after shuting in the well (static sample)

Traditional bottomhole samplers are often transferred to a sample container while still on the drilling rig. (Norsk Hydro tries to practice transfer on land when possible.) The procedure for this transfer includes:

- Measure the opening pressure of the BH sampler
- Heat the BH sampler to about 80$^{o}$C
- Mix the sample by agitation/rotation
- Transfer to sample container

The saturation pressure of the sample is measured in the sample container at the prevailing temperature.

To ensure that representative samples have been obtained, at least two (and preferably three) BH samples should have the same bubblepoint pressure at ambient temperature, within 3 to 4%.

### 3.2.7 Wellhead Sampling

If a produced oil is single phase at the wellhead then a sample can be taken upstream to the choke. Several wellhead sampling methods can be used:

- Fill a membrane sampler by displacing the backpressure fluid (ethylene glycol)
- Fill a piston cylinder sampler
- Fill an open cylinder containing mercury (sometimes not allowed offshore, e.g. in Norway)

Successful wellhead samples should be very accurate if the temperature is above the wax appearance point (WAP). Usually wellhead samples can only be taken from high-pressure, deep wells that are highly undersaturated (e.g. Embla). In general, wellhead (or bottomhole) samples are preferred for asphaltene studies.

### 3.2.8 Separator Sampling

Separator sampling is used for gas condensates and saturated oils. Separator samples are also taken for gas injection studies requiring large sample volumes, and for special studies involving analysis of asphaltene precipitation, wax (paraffin) point, emulsions, hydrates, and corrosion.

The method relies on sampling separately the gas and oil leaving the primary separator (Figure 3-1). The samples should be taken simultaneously, filling the sample containers at a constant rate of about 1 liter/minute. The 20 liter gas bottles are initially evacuated. The separator oil (about 600 cm$^3$) can be collected in a membrane bottle by displacing ethylene glycol, a piston cylinder, or a mercury-filled container (not allowed offshore Norway). A good rule-of-thumb is that it takes about one-half hour to collect a set of separator samples.

Criteria for valid separator sampling include:

- Stable separator pressure and temperature, liquid level, and flow rates. Excessive carryover (due to high rates) should be avoided.

- Critical flow through the choke, requiring that separator pressure is less than 1/2 of the wellhead flowing pressure. Sometimes this criterion cannot be achieved, and strictly speaking it is not necessary if separator conditions are stable.

Separator gas and separator oil rates are measured during the sampling to determine the ratio with which to recombine the separator samples. The recombined mixture should yield an overall fluid representing the wellstream that entered the separator. This wellstream hopefully represents the reservoir fluid. Measured separator gas rates are corrected in the laboratory using standard orifice equations.

Separator gas rate is about 3 to 10% accurate (Daniel mixer), and the liquid rate should be 2 to 5% accurate using a rotameter. Carryover of separator oil in the gas stream may be a problem for high-rate gas condensate wells (particularly lean condensate wells). As much as 30-40% of the separator oil (condensate) may be carried over in the gas stream of a lean condensate producing into a standard 20-foot separator. The separator gas sampler may or may not capture the carried-over liquid. Irregardless, the potential error in calculated wellstream composition may be significant for large carryover (low separator efficiency).

Three types of separator sampling can then be requested:

- Standard sampling
- Isokinetic sampling
- Mini-laboratory (Thorton) sampling

Standard separator sampling should almost always be collected for gas condensate and saturated oils.

If carryover is suspected, isokinetic samples can be taken to quantify the separator efficiency, and thereby establish the neccesary corrections to make a valid recombination. A more expensive alternative is the Thorton sampling technique for gas condensates.

### 3.2.9 Isokinetic Sampling

Isokinetic sampling may be recommended for lean gas condensates with documented low separator efficiency, characterized by significant carryover of separator oil into the separator gas stream. The method is based on sampling the separator gas twice:

- First, a sample of the oil-free gas is taken by sampling in the same direction as gas flows.

- Second, a sample of the separator gas containing the entrained (carryover) separator oil is taken by sampling against the direction of gas flow at a properly controlled sampling rate (isokinetically).

Comparing the two sample compositions, carryover or separator efficiency can be quantified. 1 shows the isokinetic sampling equipment.

### 3.2.10 Mini-Laboratory (Thorton) Sampling

A mixing block is placed in a vertical 2.3" flowline, upstream from a 5/64" sample line lodged perpendicular to flow. The sampling assembly is located downstream to the choke and upstream to the separator (Figure 3-1). A mini laboratory separator is used to analyze the wellstream sample by conducting a controlled multistage separation, with compositions and separator GORs measured directly, and wellstream recombination calculated onsite.

The mini-laboratory sampling approach is expensive and therefore not usually recommended. Careful separator sampling, eventually with isokinetic sample control of liquid carryover, should usually be sufficient for most gas condensate reservoirs.

### 3.2.11 Sample Treatment at the PVT Laboratory

When the samples arrive at the PVT laboratory the samples must be checked for quality and possible leakage. Several methods can be used to check sample consistency. It is important to establish which samples should be used for the PVT study, mainly based on these consistency checks.

Bottomhole and wellhead oil samples are brought to the same temperature that was used to determine the bubblepoint on the wellsite. The bubblepoint is determined for each sample, and if the bubblepoints from the laboratory and the wellsite check within 1% for a given sample then it is considered valid.

Several problems may cause lab and wellsite bubblepoints to deviate. If the oil is somewhat volatile (GOR>150 $Sm^3/Sm^3$) then it may be difficult to measure the bubblepoint graphically using a pressure-volume plot. This is a typical problem for high bubblepoint oils ($p_b$>250 bar). Another problem is that equilibrium may not have been reached at each pressure when measurements were conducted on the wellsite. Finally, the pressure gauges may have been improperly calibrated.

Separator samples also can be checked for leakage (look in the sample box!). The oil sample is checked by measuring the bubblepoint at separator temperature. If the measured bubblepoint is within about 1-2% of the separator pressure then the oil sample is considered valid.

The pressure in the gas sample bottle is checked against the separator pressure. Note that the opening pressure at room temperature may be larger than separator pressure because the sample container may have been colder than room tempearature when filled at the separator. The basic control relation for checking opening pressure of gas samples is

$$p_{\text{opening}} = p_{\text{sp}} \frac{T_{\text{opening}}}{T_{\text{sp}}} \qquad (3\text{-}1)$$

where pressures and temperatures are given in absolute units. It may be difficult to establish the proper "$T_{sp}$" in this equation, as the actual temperature may be affected by the atmospheric conditions, as well as temperature reduction during the "flashing" of gas into the sample bottle.

## 3.3 Compositional Analysis and Quality Control

PVT studies are usually based on one or more samples taken during a production test. Bottomhole samples can be obtained by wireline using a high-pressure container, either during the production test or during a shutin period. Separator samples may also be taken during a production test.

This section discusses how wellstream compositions are determined. The standard approach consists of first separating the high-pressure sample into low-pressure gas and oil samples which are each analyzed using gas chromatography (GC). The overall mixture composition is obtained by mathematically recombining the separated gas and oil compositions.

The standard components quantified in petroleum reservoir fluids include

- *Non-Hydrocarbons* $N_2$ $CO_2$ $H_2S$

- *Hydrocarbons* $C_1$ $C_2$ $C_3$ $iC_4$ $nC_4$ $iC_5$ $nC_5$ $C_{6s}$ $C_{7+}$
  (or $C_7$ $C_8$ $C_9$ $C_{10+}$)

Table 3-2 lists example compositions of the main fluid types, together with relevant reservoir and surface properties. Figure 3-1 illustrates the classification of fluid types based on composition in the form of a simple ternary diagram. Also shown is the classification based on producing (initial) gas-oil ratio and oil-gas ratio.

### 3.3.1 Gas Chromatography

Compositional measurements are made using gas chromatography and sometimes true boiling point (TBP) distillation. Gas chromatography measures the weight (mass) fraction of individual components in a mixture. TBP analysis gives additional information about the amount and properties of heavier components (heptanes and heavier, $C_{7+}$).

Gas chromatography is based on selective separation of components as temperature is increased in a capillary tube (Figure 3-1)[5]. The sample is injected to the GC, followed by a carrier gas such as helium or nitrogen. As temperature increases, the lighter components separate and move together with the carrier gas to a flaming ion detector (FID).

Instead of a carrier gas, a carrier liquid or supercritical fluid can be used to transport separated components. These methods are referred to as liquid chromatography and supercritical fluid chromatography, respectively.

The FID signal for a component is shown as a peak on the chromatographic line (Figure 3-1). The relative mass of a component is given by the area under the peak, divided by the total area created by all components in the mixture. Note that FID only responds to organic compounds. A particular component can be identified by the time (temperature) when its peak appears. For example, the methane peak appears before the ethane peak, which occurs before the propane peak, and so on.

A thermal capacity detector (TCD) may be used in some chromatographs. This dector measures the difference in thermal capacity between the pure carrier gas and the carrier gas mixed with the component being detected. The difference in thermal capacity is a function of the number of molecules of the component. In contrast to the FID, which measures relative mass of each component, the TCD measures relative moles of each component. Also, the TCD can be used for both hydrocarbon and nonhydrocarbon compounds.

Norsk Hydro uses TCD for non-hydrocarbons, and FID for hydrocarbons.

Accurate quantitative GC analysis depends on reproducible retention times, and known dector response for the range of components being analyzed. Several sources of error in GC analysis are given below:

- Improper handling of the sample before injection
- Method used for injection
- Decomposition of sample during analysis
- Bad chromatographic system; tailing or overuse of the system
- Variation in detector response
- Calibration errors
- Error in response area measurements (integration)

### 3.3.2 Natural Gas Analysis

A packed column with TCD is used to separate nonhydrocarbon (inorganic) components such as nitrogen, carbon dioxide, and hydrogen sulphide, as well as methane and ethane. Chromatographic separation using FID in a capillary column is used for components methane through decane.

An external standard and response factor are used to quantify the analysis more precisely. The response factor for FID includes (implicitly) the molecular weight to convert from mass to mole fraction. Finally, the FID and TCD analyses are combined using ethane analyses to "bridge" the combination of the two analyses, where normalization with a volume correction is used.

### 3.3.3 Oil/Condensate GC Analysis

A capillary column with FID is used to analyse atmospheric oil and condensate samples. The analysis can be carried out to carbon numbers 30 or greater, but an internal standard such as squaline is usually needed to ensure accurate quantitative conversion of response areas to mass fractions. Figure 3-1 shows a typical oil chromatogram (of a stock-tank condensate).

Simulated distillation (SIMDIS) by GC analysis may also be used. SIMDIS is usually conducted with a 30-50 m capillary column using Helium as the carrying gas with a diluted sample (1:100), temperatures from $50^o$-$280^oC$ at $4^oC$/min.

Conversion from mass fraction to mole fraction requires molecular weights of all components. Because molecular weights are not measured, and for a given carbon number the molecular weight may vary by 5 or 10 molecular weight units (depending on the type of hydrocarbons found in the particular carbon number), conversion to mole fractions is only approximate.

Many laboratories use paraffin molecular weights (given by the relation $M_i$=14i+2) to convert GC mass fractions to mole fractions. The molecular weights given by Katz and Firoozabadi[6] for carbon numbers up to $C_{45}$ are probably more accurate for stock tank oils and condensates (Charts 3 and 4 in the *Fluid Properties Data Book*)[7].

### 3.3.4 True Boiling Point (TBP) Analysis

True boiling point distillation may supplement traditional GC analysis of oil and condensate samples. TBP distillation separates an oil into cuts or fractions according to the range of boiling points used for separation. Figure 3-1 defines typical refined petroleum products in terms of carbon number fractions. Figure 3-1 illustrates the range of carbon number fractions containing various hydrocarbon compounds (e.g. n-alkanes).

The recommended standard[6] uses normal boiling points of paraffins to separate individual carbon number fractions. To avoid decomposition ("cracking") of the oil during distillation, vacuum is applied in four stages to reduce the distillation temperatures for heavier components:

- Atmospheric (1013.0 mbar)
- 100 torr (133.0 mbar)
- 10 torr (13.0 mbar)
- 2 torr (2.6 mbar)

The distillation usually proceeds from $C_7$ (or $C_9$) to about $C_{25}$, plus a residue (~$C_{26+}$). Figure 3-1 shows a TBP distillation apparatus recommended in ASTM D-2892.[8]

The mass, volume, molecular weight, and density (specific gravity) of each distilled fraction is measured directly. Table 3-4 gives results of TBP distillation of stock-tank oil. Reported densities are at a temperature of $15^oC$ ($60^oF$) and atmospheric pressure. Some of the heavier fractions may have a higher pour point than 15°C (i.e the fraction is not fluid at 15°C), and the measured density is made at a higher temperature (Table 3-5). This density is then corrected to the reported value using standard thermal correction tables.

Because the separation of components in a given distillation cut is only approximate, some overlap is observed. For example, the $C_{12}$ cut may contain 10% $C_{11}$ compounds, 85% $C_{12}$ compounds, and 5% $C_{13}$ compounds. The overlap worsens at lower distillation pressures because the difference in distillation temperatures is reduced between cuts. Table 3-6 and Figure 3-1 show the overlap for an example TBP distillation.

The overlap can be corrected to yield an "ideal" distillation curve (Table 3-7). The resulting ideal distillation curve should be quite similar to the simulated distillation curve, as shown in Figure 3-1.

One advantage with TBP analysis is that measured molecular weights are available for converting from mass to mole fraction. Molecular weights are measured using a cryoscopic method (freezing point depression), a method that is sensitive to error and probably reliable at best to about ±2 to 5%. Measured molecular weights are compared with GC-based calculated molecular weights in Table 3-5.

Table 3-8 summaries the GC/TBP analysis of the example stock-tank oil, where results are provided through $C_{10+}$.

Average boiling points are taken from the tables of Katz and Firoozabadi.[6] With these boiling points and with measured specific gravities the critical properties and acentric factors of the fractions can be estimated from correlations. Critical properties are needed in PVT calculations with an equation of state (EOS). Reservoir, pipeflow, and process simulations may also require EOS calculations.

It is recommended that at least one TBP analysis be measured for each reservoir fluid in a given field. As an extreme example, a field such as Visund might require up to four TBP studies:

- (1) gas cap and (2) equilibrium oil samples in the Brent formation
- (3) gas condensate in the Statfjord formation
- (4) near-critical oil in the Lunde formation

Note that it may be difficult to use several TBP analyses to come up with a single EOS characterization for reservoirs with multiple fluids (e.g. compositional variation or gas cap/oil). The examples in sections 5.5.2 and 5.6.2 discuss the use of TBP data in EOS fluid characterization.

Mass fractions measured from TBP analysis should be reasonably close to mass fractions determined from simulated distillation. However, SIMDIS does not provide properties of the individual fractions (molecular weight and density).

### 3.3.5 Bottomhole Sample Composition

Table 3-8 shows the reported wellstream composition of a reservoir oil, where $C_6$, $C_7$, $C_8$, $C_9$, and $C_{10+}$ specific gravities and molecular weights are also reported. In the example report, composition is given both as mole and weight percent, though many laboratories only report molar composition. Experimentally, the composition of a bottomhole sample is determined by (Figure 3-3, Figure 3-1):

- Flashing the sample to atmospheric conditions.
- Measuring the quantities of surface gas and oil.
- Determining the normalized weight fractions of surface samples by gas chromatography.
- Measuring molecular weight and specific gravity of the surface oil.
- Converting weight fractions to normalized mole fractions.
- Recombining mathematically to the wellstream composition.

The most probable source of error in wellstream composition of a bottomhole sample is the surface oil molecular weight which usually is accurate within 5 to 10%. TBP data, if available, can be used to check surface oil molecular weight.

### 3.3.6 Recombined Sample Composition

Table 3-10 presents the separator oil and gas compositional analyses of a gas condensate fluid, together with recombined wellstream composition. The separator oil composition is obtained using the same procedure as for bottomhole oil samples. This involves bringing the separator oil to standard conditions, measuring properties and compositions of the resulting surface oil and gas, and recombining these compositions to give the separator oil composition which is reported as shown in Table 3-10.

The separator gas sample is introduced directly into a gas chromatograph. Weight fractions are converted to mole fractions using appropriate molecular weights. $C_{7+}$ molecular weight is back-calculated using measured separator gas specific gravity.

The separator oil and gas compositions can be checked for consistency using the Hoffman et al.[9] K-value method and Standing's[10] low-pressure K-value equations (section 3.4.10).

Table 3-12 gives a summary of equations used to correct test separator gas-oil ratio for use in recombination.

## 3.4 PVT Experiments

### 3.4.1 Multistage Separator Test

The multistage separator test is conducted on oil samples primarily to provide a basis for converting differential liberation data from a residual oil to a stock-tank oil basis (see section 3.4.4).

Occasionally, several separator tests are conducted to determine the separator conditions that maximize stock-tank oil production. Usually two or three stages of separation are used, with the last stage being at atmospheric pressure and near-ambient temperature (15 to 25°C). The multistage separator test can also be conducted for rich gas condensate fluids.

Figure 3-1 illustrates schematically how the separator test is performed. Initially the reservoir sample is brought to saturation conditions and the volume is measured. The sample is then brought to the pressure and temperature of the first-stage separator. All of the gas is removed and the oil volume at the separator stage is noted, together with the volume, number of moles, and specific gravity of the removed gas. If requested, the composition of gas samples can be measured.

The oil remaining after gas removal is brought to the conditions of the next separator stage. The gas is again removed and quantified by moles and specific gravity. Oil volume is noted, and the process is repeated until stock-tank conditions are reached. The final oil volume and specific gravity are measured at 15.5$^o$C and one atmosphere.

Table 3-13 gives results from a three-stage separator test. Gas removed at each stage is quantified as standard gas volume per volume of stock-tank oil. Sometimes an additional column of data is reported, giving standard gas volume per volume of separator oil; note, you can not add GORs reported relative to separator oil volumes.

### 3.4.2 Constant Composition Expansion - Oils

For an oil sample the constant composition expansion (CCE) experiment is used to determine the bubblepoint pressure, the undersaturated oil density and isothermal oil compressibility, and the two-phase volumetric behavior at pressures below the bubblepoint. Table 3-14 presents data from an example CCE experiment for a reservoir oil.

The procedure for the CCE experiment is shown in Figure 3-1. A PVT cell is filled with a known mass of reservoir fluid and brought to reservoir temperature. Temperature is held constant during the experiment. The sample is initially brought to a condition somewhat above the initial reservoir pressure, ensuring that the fluid is single phase. As the pressure is lowered, oil volume expands and is recorded.

The fluid is agitated at each pressure by rotating the cell. This avoids the phenomenon of *supersaturation* or *metastable equilibrium* where a mixture remains as a single phase, even though it should split into two phases. Sometimes supersaturation occurs 3 to 7 bar below the actual bubblepoint pressure. By agitating the mixture at each new pressure, the condition of supersaturation is avoided and the bubblepoint can be determined more accurately.

Just below the bubblepoint the total volume will increase more rapidly because gas evolves from the oil. This yields a higher system compressibility. Visually, gas can be seen at the top of the cell (if a visual cell is used). The total volume is recorded after the two-phase mixture is brought to equilibrium. Pressure is lowered in steps of 1 to 15 bar, where equilibrium is obtained at each pressure. When the lowest pressure is reached, total volume is 3 to 5 times larger than the original bubblepoint volume.

The recorded cell volumes are plotted versus pressure, and the resulting curve should be similar to one of the curves shown in Figure 3-1. For a "black oil" the discontinuity in volume at the bubblepoint is sharp. The bubblepoint pressure and bubblepoint volume are easily read from the intersection of the pressure-volume trends from the single-phase and the two-phase regions.

Volatile oils do not exhibit the same clear discontinuity in volumetric behavior at the bubblepoint pressure (Figure 3-1). Instead, the p-V curve is practically continuous in the region of the bubblepoint because undersaturated oil compressibility is similar to the effective two-phase compressibility just below the bubblepoint. This makes it difficult to determine the bubblepoint of volatile oils using a pressure-volume plot.[a] Instead, a windowed cell is used for visual observation of the first bubble of gas at the bubbleopint. Liquid shrinkage below the bubblepoint can also be measured in a visual cell during the constant composition expansion.

Reported data from commercial laboratories usually include bubblepoint pressure, bubblepoint density or specific volume, and isothermal compressibility of the undersaturated oil at pressures above the bubblepoint. The oil's thermal expansion may also be reported, indicated by the ratio of undersaturated oil volume at a specific pressure and reservoir temperature to the oil volume at the same pressure and a lower temperature.

Total volume below the bubblepoint can be correlated by the Y function, defined as

$$Y \equiv \frac{(p_b/p)-1}{V_{rt}-1} = \frac{(p_b/p)-1}{(V_t/V_b)-1} \tag{3-2}$$

where p and $p_b$ are given in absolute pressure units. Plotting Y versus pressure should yield a straight line, as shown in Figure 3-1. The linear trend can be used to smooth total volume data at pressures below the bubblepoint.

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[a] Reported bubblepoint pressures measured at the wellsite on bottomhole samples of volatile oils are obviously subject to large inaccuracy because a pressure-volume plot is used. This should be kept in mind when comparing laboratory-measured bubblepoint with wellsite-determined bubblepoint in the selection (rejection) of valid samples.

### 3.4.3 Constant Composition Expansion - Gas Condensates

The CCE experiment for a gas condensate reports the total relative volume, defined as the volume of the gas or gas-plus-oil mixture divided by the dewpoint volume. Z-factors are also reported, at the dewpoint pressure and above.[a] Table 3-15 and Figure 3-1 gives example CCE data for a gas condensate.

Wet-gas FVF (or its inverse) is reported at the dewpoint and/or initial reservoir pressure. These values represent the gas equivalent or wet-gas volume at standard conditions produced from one volume of reservoir gas.

Most CCE experiments are conducted in a visual cell for gas condensates. Relative oil (condensate) volumes are reported at pressures below the dewpoint, where relative oil volume is usually defined as the oil volume divided by the total volume of gas-plus-oil; in some reports, however, relative oil volume is defined as the oil volume divided by the dewpoint volume (Norsk Hydro practice).

### 3.4.4 Differential Liberation Expansion

The differential liberation expansion (DLE) experiment is designed to approximate the depletion process of an oil reservoir, and thereby provide suitable PVT data for calculating reservoir performance. Figure 3-1 illustrates the laboratory procedure of a DLE experiment. Figure 3-1 through Figure 3-1 and Table 3-16 through Table 3-19 give DLE data for an oil sample.

A blind cell is filled with an oil sample which is brought to a single phase at reservoir temperature. Pressure is decreased until the fluid reaches its bubblepoint, where the oil volume is recorded; knowing the initial mass of the sample, the bubblepoint density can be calculated.

The pressure is decreased below the bubblepoint and the cell is agitated until equilibrium is reached. All gas is removed at constant pressure, and the volume, moles, and specific gravity of the removed gas are measured. Sometimes gas compositions are also measured. The remaining oil volume is also recorded. This procedure is repeated 10 to 15 times at decreasing pressures, and finally at atmospheric pressure.

The final oil is cooled, where the resulting "residual" oil volume and specific gravity are measured (or calculated) at 15.5°C. Residual oil composition may also be reported.[b]

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[a] If Z-factors are also reported *below* the dewpoint then they represent ficticious, non-physical quantities that *should not be used*.

[b] *None* of the data reported for the residual oil should be used as data in doing an EOS fluid characterization. The reason is simply that the process used in the lab from the next-to-last stage to atmospheric pressure (and reservoir temperature) is not a single flash as simulated by an EOS. The last-stage depletion process may be conducted differently by various laboratories; usually it is a bleeding process, or bleeding/flash/bleeding process.

Based on measured data, other properties are *calculated*, including differential solution gas-oil ratio ($R_{sd}$), differential oil FVF ($B_{od}$), oil density, and gas Z-factor.

### 3.4.5 Converting from Differential to Stock-Tank Basis

Traditionally the most important step in the application of oil PVT data for reservoir calculations is the conversion of differential solution gas-oil ratio ($R_{sd}$) and differential oil FVF ($B_{od}$) to a stock-tank oil basis. For engineering calculations, volume factors $R_s$ and $B_o$ are used to relate reservoir oil volumes to produced surface volumes.

Differential properties $R_{sd}$ and $B_{od}$ reported in the DLE report are relative to *residual oil volume*, i.e., the oil volume at the end of the DLE experiment, corrected from reservoir to standard temperature. The equations traditionally used to convert differential volume factors to a stock-tank basis are:

$$R_s = R_{sb} - (R_{sdb} - R_{sd})\left(\frac{B_{ob}}{B_{odb}}\right) \tag{3-3}$$

$$B_o = B_{od}\left(\frac{B_{ob}}{B_{odb}}\right) \tag{3-4}$$

where $B_{ob}$ and $R_{sb}$ are the bubblepoint oil FVF and solution GOR, respectively, from a multistage separator flash. $R_{sdb}$ and $B_{odb}$ are differential volume factors at the bubblepoint pressure. The term ($B_{ob}/B_{odb}$) is used to eliminate the residual oil volume from the $R_{sd}$ and $B_{od}$ data. Note that the conversion from differential to "flash" data depends on the separator conditions because $B_{ob}$ and $R_{sb}$ depend on separator conditions.

The conversions given by Eqs. (3-3) and (3-4) are only approximate. Figure 3-1 shows the conversion of differential $B_{od}$ to flash $B_o$ for the example oil with differential data reported in Table 3-16 through Table 3-19.

A more accurate method was suggested by Dodson et al.[11] Their method requires that some of the equilibrium oil be taken at each stage of a depletion experiment (DLE, CCE, or CVD (see section 3.4.6)) and flashed through a multistage separator. The multistage separation gives $R_s$ and $B_o$ directly. This laboratory procedure is costly and time-consuming, and therefore never used. However, the method is readily simulated with an equation of state model (Whitson and Torp[12]; Coats[13]).

Figure 3-1 shows oil volume factors and solution GORs calculated using the standard conversion given by Eqs. (3-3) and (3-4), compared with the Dodson method (Whitson and Torp procedure) using an EOS. The oil is slightly volatile, and it is seen that the approximate conversion gives approximately the same results as using the more rigorous Dodson method.

Figure 3-1 shows a similar comparison for a highly (near-critical) volatile oil. The difference in both oil volume factor and solution GOR is significant, and clearly the traditional conversion of DLE data can not be used for this type of fluid.

It should be realized that even when dealing with a slightly volatile oil (GOR>125 $Sm^3/Sm^3$), a modified black-oil (MBO) PVT formulation should be used in reservoir calculations (material balance and simulation). The MBO formulation is compared with the traditional black-oil formulation in Figure 3-1. The main difference is that the MBO treatment accounts for the ability of reservoir gas to volatilize intermediate and heavier components that produce a suface condensate when produced.

The ratio of surface condensate produced from reservoir gas to surface gas produced from reservoir gas is the solution oil-gas ratio $R_V$ (sometimes written $r_s$). The gas FVF also must be adjusted from the traditional definition to account for the reservoir gas that becomes condensate at the surface (i.e. that the moles of reservoir gas does not equal the moles of surface gas, as is assumed in the traditional definition of gas FVF). The resulting gas FVF is called "dry" gas FVF, with symbol $B_{gd}$.

### 3.4.6 Constant Volume Depletion

The constant volume depletion (CVD) experiment is designed to provide volumetric and compositional data for gas condensate (and volatile oil) reservoirs producing by pressure depletion. The stepwise procedure of a CVD experiment is shown schematically in Figure 3-1. Table 3-19 and Table 3-21 give CVD data for an example gas condensate fluid.

The CVD experiment provides data that can be used directly in reservoir engineer calculations, including:

- Reservoir material balance giving recovery of total wellstream (wet gas recovery) versus average reservoir pressure.
- Produced wellstream composition and surface products (sales gas, condensate, and NGLs) versus reservoir pressure.
- Average oil saturation in the reservoir (liquid dropout and revaporization) that occurs during pressure depletion.

For most gas condensate reservoirs producing by depletion, the recoveries and oil saturations versus pressure from the CVD analysis closely approximate actual field performance.[a] If other recovery mechanisms such as water drive and gas

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[a] The basic assumption is that hydrocarbons condensed in the reservoir, *on the whole* (i.e. neglecting local saturation effects near the wellbore), do not flow in significant amounts to production wells. The reason is simply that the relative mobility of oil is much smaller than the reservoir gas mobility.

cycling are considered, the basic data required for reservoir engineering are still taken mainly from a CVD report.

### 3.4.7 PVT Data Accuracy

The accuracy of PVT measurements is difficult to quantify. Norsk Hydro has, however, studied the problem and Table 3-22 gives guidelines for measurement accuracies of most PVT data.

### 3.4.8 PVT Consistency Checks

The quality of PVT data may vary from poor to excellent. It may not be obvious, however, when inaccurate data are reported. Several methods can be used to determine the quality of reported PVT data. The recommended consistency checks given below should be used for PVT data that will be used in reservoir studies, or in the development of an equation of state characterization.

### 3.4.9 Watson Characterization Factor

The $C_{7+}$ molecular weight is highly susceptible to error, with an accuracy ranging from 2 to 10%. Specific gravity of $C_{7+}$, on the other hand, should be accurate within a fraction of a percent.

The characterization factor $K_w$ was introduced by Watson[14] to qualitatively describe the relative paraffinicity of a petroleum product. $K_w$ is defined as $K_w = T_b^{1/3}/\gamma$, where $T_b$ is the normal boiling point in $^oR$ and $\gamma$ is the specific gravity relative to water.

Stock-tank oils and condensates contain many hundreds of hydrocarbon compounds. Because STO consists mainly of the $C_{7+}$ material, the characterization or "paraffinicity" of a reservoir fluid can be described by the Watson characterization factor of the $C_{7+}$ fraction.

The following table gives the range of the Watson characterization factor for pure compounds in the three main hydrocarbon families, and for stock-tank oils/condensates.

| Hydrocarbon Type | Pure Compound | Stock-Tank Oil/ Condensate ($C_{7+}$) |
|---|---|---|
| Paraffin | 12-14 | 12-12.5 |
| Napthene | 10-12 | |
| Aromatic | 8-10 | 11-11.5 |

Whitson[15] gives an approximate relation for $K_w$ that can be used for heptanes-plus,

$$K_{w7+} = 4.5579\, M_{7+}^{0.15178}\, \gamma_{7+}^{-0.84573} \qquad (3\text{-}5)$$

Austad et al. show that for a given formation in a reservoir, $K_{w7+}$ should be very constant, even during depletion and even if the STO gravity varies initially (Figure 3-1).

Based on this observation, it is recommended that $K_{w7+}$ be calculated for each new PVT sample in a field/reservoir. A plot of $M_{7+}$ versus $\gamma_{7+}$ can be updated with each new sample, where a line of constant $K_{w7+}$ is drawn for the field average. Deviation of ±0.03 in $K_{w7+}$ is acceptable. Larger deviations in $K_{w7+}$ from the field/reservoir average may (probably) indicate an error in the measured $M_{7+}$.

If larger errors in $M_{7+}$ are found, then potential errors in reported molar composition should be checked.

### 3.4.10 Hoffman et al. Kp-F Plot

The consistency of separator gas and oil compositions can be checked using a diagnostic plot proposed by Hoffman, Crump, and Hocott.[9] They show that K-values (on a log scale) plotted versus a component factor $F_i$ (on a linear scale) should result in a straight-line relationship.

To apply this method to separator samples, the K-values are calculated first from separator gas and oil compositions, $K_i=y_i/x_i$ where $y_i$=separator gas molar composition and $x_i$=separator oil molar composition.

The Hoffman characterization factor $F_i$ is given by

$$F_i = b_i (1/T_{bi} - 1/T_{sp}) \tag{3-6}$$

where $T_{bi}$ is the normal boiling point in $^oR$, $T_{sp}$ is the separator temperature in $^oR$, and $b_i$ is a component constant given formally by

$$b_i = \frac{\log(p_{ci} / p_{sc})}{1/T_{bi} - 1/T_{ci}} \tag{3-7}$$

where $p_{ci}$ is critical pressure in psia, $p_{sc}$ is standard pressure in psia, and $T_{ci}$ is critical temperature in $^oR$.

Standing[10] gives modified values of $b_i$ and $T_{bi}$ to be used with the Hoffman et al. method, as shown in Table 3-23. Standing also gives the expected slope and intercept of the line as a function of pressure and temperature for typical separator conditions,

$$\log K_i p_{sp} = a + c F_i \tag{3-8}$$

where

$$\begin{aligned} a &= 1.20 + 4.5\times10^{-4} p_{sp} + 15.0\times10^{-8} p_{sp}^2 \\ c &= 0.89 - 1.7\times10^{-4} p_{sp} - 3.5\times10^{-8} p_{sp}^2 \end{aligned} \tag{3-9}$$

with $p_{sp}$ given in psia.

According to Standing, the correlations for a and c are valid up to pressures of 70 bar and temperatures from 5 to 95°C.

A plot of measured separator K-values using this method should not deviate significantly from the Standing straight line. Heptanes plus, nonhydrocarbons, and components with small amounts (<0.5 mol-%) in either the separator oil or gas sample may deviate from the straight line without causing concern. However, if the key hydrocarbons methane through hexane show significant deviation from the straight line, the compositional analysis should be used with scrutiny.

Figure 3-1 shows a Kp-F plot for the separator sample given earlier (Table3-10).

### 3.4.11 Correcting GOR for Liquid Carryover

The reported separator GOR ($R_{sp}$) may be in error for several reasons:

- Incorrect separator oil rate
- Incorrect separator gas rate
- Carryover of separator oil in separator gas stream
- Gas in the oil line
- Incorrect measurement of the "meter factor"
- Combination of the above

It is probably reasonable to say that reported GOR has an accuracy of 5 to 15%, with even greater errors possible for lean gas condensates producing at high rates.

The recombined wellstream $z_i$ composition is calculated from

$$z_i = F_{gsp}\ y_i + (1 - F_{gsp})\ x_i \tag{3-10}$$

where $F_{gsp}$ is the total mole fraction of total wellstream that leaves the separator in the gas stream,[a]

$$F_{gsp} = \left[ 1 + 23.68 \frac{\rho_{osp}}{M_{osp}\, R_{sp}} \right]^{-1} \tag{3-11}$$

where $\rho_{osp}$ is the separator oil density in kg/m$^3$, $M_{osp}$ is the separator oil molecular weight (kg/kmol), and $R_{sp}$ is separator gas-oil ratio in Sm$^3$/sep. m$^3$.

If the GC analyses are done properly, both separator oil composition $x_i$ and separator gas composition $y_i$ should be correct, even if carryover is a problem.

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[a] When carryover occurs, $F_{gsp}$ calculated using test GOR will *also* include the entrained liquid that is carried over in the gas stream leaving the separator. This is because the measured gas rate includes the amount (moles) of carryover.

The traditional method of sampling gas (downstream) will minimize the amount of carryover that enters the gas sample container. Also, if the gas sample is brought to separator conditions before charging the chromatograph, only equilibrium gas will be removed for analysis, and the carryover separator oil will remain in the sample container.

We can usually assume with reasonable accuracy that the separator gas and oil compositions, as reported, can be used for recombination if the Hoffman et al. plot is acceptable. To obtain a valid wellstream composition from Eq. (3-10), however, the recombination GOR may need to be corrected (for one of several reasons).

If carryover exists then the separator gas rate reflects both the amount (moles) of separator gas $n_g$ *plus* the moles of carryover separator oil $\Delta n_o$, the total being expressed as a standard gas volume (Figure 3-1). The separator oil rate reflects the total separator oil rate $n_o$ *less* the moles of separator oil carryover (i.e. $n_o^* = n_o - \Delta n_o$). In terms of an overall molar balance,

$$\begin{aligned} n &= n_g + n_o \\ &= n_g + (n_o^* + \Delta n_o) \end{aligned} \tag{3-12}$$

and in terms of a component molar balance,

$$\begin{aligned} z_i n &= y_i n_g + x_i n_o \\ &= y_i n_g + x_i \Delta n_o + x_i n_o^* \\ &= y_i^* (n_g + \Delta n_o) + x_i n_o^* \end{aligned} \tag{3-13}$$

where $y_i$ and $x_i$ are standard separator samples (i.e. true equilibrium phase) compositions (assuming downstream sampling of the separator gas collects little if any of the carryover separator oil). An isokinetic gas sample, on the other hand, represents the separator gas plus carryover separator oil $y_i^*$.

Defining the separator oil carryover $\delta_{osp}$ as

$$\delta_{osp} \equiv \frac{\Delta n_o}{n_o} \tag{3-14}$$

the effect of carryover on wellstream composition is calculated by first correcting the test gas mole fraction $(F_{gsp})_{test}$ calculated from the test GOR. The corrected gas mole fraction reflects the *true* fraction of the total wellstream that is separator gas $(n_g/n)$,

$$\begin{aligned} (F_{gsp})_{corr} &= \frac{n_g}{n_g + n_o} = \frac{n_g}{n} \\ &= \frac{(F_{gsp})_{test} - \delta_{osp}}{1 - \delta_{osp}} \end{aligned} \tag{3-15}$$

Furthermore, the measured test separator GOR $(R_{sp})_{test}$ can be corrected for carryover to yield the true separator GOR,

$$(R_{sp})_{corr} = (R_{sp})_{true} = (R_{sp})_{test} \frac{1/(F_{gsp})_{test} - 1}{1/(F_{gsp})_{corr} - 1} \tag{3-16}$$

Table 3-12 and section 4.3.2 discuss the corrections to reported wellsite separator test GOR. The corrections result in a test GOR $(R_{sp})_{test}$ that is then used in Eq. (3-11) to determine $(F_{gsp})_{test}$ (referred to in the equations above).

## 3.5 References

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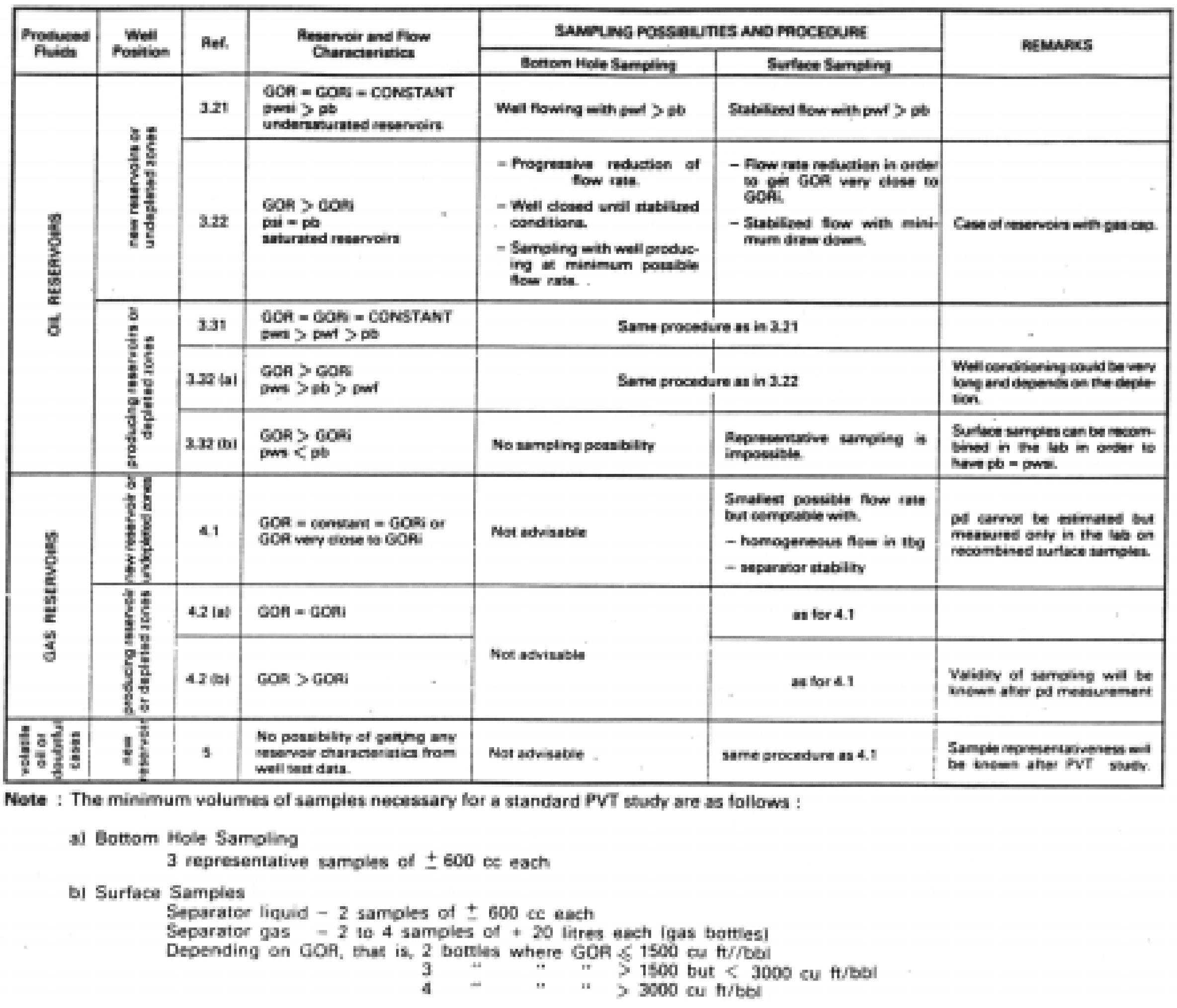
**Table 3-1**

| **Laboratory Analysis** | **Oils** | **Gas Condensates** |
|---|---|---|
| *Standard* | | |
| Bottomhole Sample Composition | ● | ○ |
| Recombined Separataor Composition | ○ | ● |
| $C_{7+}$ TBP Distillation | ○ | ○ |
| $C_{7+}$ Simulated Distillation (SIMDIS) | ○ | ○ |
| Constant Composition Expansion | ● | ● |
| Multistage Surface Separation | ● | ○ |
| Differential Liberation | ● | N |
| Constant Volume Depletion | ○ | ● |
| *Special* | | |
| Multicontact Gas Injection | ○ | ○ |
| Wax Point Determination | ○ | ○ |
| Asphaltene Precipitation | ○ | ○ |
| Slimtube Analysis (MMP/MME) | ○ | ○ |
| Water Analysis<br>Salinity, salt composition, solution gas ratio $R_{sw}$ and solution gas composition, water FVF $B_w$, density | ○ | ○ |
| | ● Standard<br>○ Can Be Performed<br>N Not Performed | |

**Table 3-2**



| Produced Fluids | Well Position | Ref. | Reservoir and Flow Characteristics | SAMPLING POSSIBILITIES AND PROCEDURE | | REMARKS |
|---|---|---|---|---|---|---|
| | | | | Bottom Hole Sampling | Surface Sampling | |
| OIL RESERVOIRS | new reservoirs or undepleted zones | 3.21 | GOR = GORi = CONSTANT<br>pwsi > pb<br>undersaturated reservoirs | Well flowing with pwf > pb | Stabilized flow with pwf > pb | |
| | | 3.22 | GOR > GORi<br>psi = pb<br>saturated reservoirs | – Progressive reduction of flow rate.<br>– Well closed until stabilized conditions.<br>– Sampling with well producing at minimum possible flow rate. | – Flow rate reduction in order to get GOR very close to GORi.<br>– Stabilized flow with minimum draw down. | Case of reservoirs with gas cap. |
| | producing reservoirs or depleted zones | 3.31 | GOR = GORi = CONSTANT<br>pws > pwf > pb | Same procedure as in 3.21 | | |
| | | 3.32 (a) | GOR > GORi<br>pws > pb > pwf | Same procedure as in 3.22 | | Well conditioning could be very long and depends on the depletion. |
| | | 3.32 (b) | GOR > GORi<br>pws < pb | No sampling possibility | Representative sampling is impossible. | Surface samples can be recombined in the lab in order to have pb = pwsi. |
| GAS RESERVOIRS | new reservoir or undepleted zones | 4.1 | GOR = constant = GORi or GOR very close to GORi | Not advisable | Smallest possible flow rate but compatable with.<br>– homogeneous flow in tbg<br>– separator stability | pd cannot be estimated but measured only in the lab on recombined surface samples. |
| | producing reservoir or depleted zones | 4.2 (a) | GOR = GORi | Not advisable | as for 4.1 | |
| | | 4.2 (b) | GOR > GORi | | as for 4.1 | Validity of sampling will be known after pd measurement |
| volatile oil or doubtful cases | new reservoir | 5 | No possibility of getting any reservoir characteristics from well test data. | Not advisable | same procedure as 4.1 | Sample representativeness will be known after PVT study. |

**Note** : The minimum volumes of samples necessary for a standard PVT study are as follows :

a) Bottom Hole Sampling
3 representative samples of ± 600 cc each

b) Surface Samples
Separator liquid – 2 samples of ± 600 cc each
Separator gas – 2 to 4 samples of + 20 litres each (gas bottles)
Depending on GOR, that is, 2 bottles where GOR ≤ 1500 cu ft//bbl
3 " " " > 1500 but < 3000 cu ft/bbl
4 " " " > 3000 cu ft/bbl

## Table 3-3

| Component/ Properties | Dry Gas | Wet Gas | Gas Condensate | Near-Critical Oil | Volatile Oil | Black Oil |
|---|---|---|---|---|---|---|
| $CO_2$ | 0.10 | 1.41 | 2.37 | 1.30 | 0.93 | 0.02 |
| $N_2$ | 2.07 | 0.25 | 0.31 | 0.56 | 0.21 | 0.34 |
| $C_1$ | 86.12 | 92.46 | 73.19 | 69.44 | 58.77 | 34.62 |
| $C_2$ | 5.91 | 3.18 | 7.80 | 7.88 | 7.57 | 4.11 |
| $C_3$ | 3.58 | 1.01 | 3.55 | 4.26 | 4.09 | 1.01 |
| $iC_4$ | 1.72 | 0.28 | 0.71 | 0.89 | 0.91 | 0.76 |
| $nC_4$ |  | 0.24 | 1.45 | 2.14 | 2.09 | 0.49 |
| $iC_5$ | 0.50 | 0.13 | 0.64 | 0.90 | 0.77 | 0.43 |
| $nC_5$ |  | 0.08 | 0.68 | 1.13 | 1.15 | 0.21 |
| $C_{6s}$ |  | 0.14 | 1.09 | 1.46 | 1.75 | 1.61 |
| $C_{7+}$ |  | 0.82 | 8.21 | 10.04 | 21.76 | 56.40 |
| $M_{7+}$ |  | 130 | 184 | 219 | 228 | 274 |
| $\gamma_{7+}$ |  | 0.763 | 0.816 | 0.839 | 0.858 | 0.920 |
| $K_{w7+}$ |  | 12.00 | 11.95 | 11.98 | 11.83 | 11.47 |
| GOR, $Sm^3/Sm^3$ | ∞ | 18,700 | 970 | 650 | 265 | 53 |
| OGR, $Sm^3/Sm^3$ | 0 | 0.000053 | 0.00103 | 0.00154 |  |  |
| $\gamma_o$ |  | 0.751 | 0.784 | 0.802 | 0.835 | 0.910 |
| $\gamma_{API}$ |  | 57 | 49 | 45 | 38 | 24 |
| g |  | 0.61 | 0.70 | 0.71 | 0.70 | 0.63 |
| $p_{sat}$, bara |  | 236 | 452 | 484 | 374 | 194 |
| $B_{sat}$, $m^3/Sm^3$ |  | 0.0051 | 0.0039 | 2.78 | 1.73 | 1.16 |
| $\rho_{sat}$, $kg/m^3$ |  | 154 | 428 | 492 | 612 | 823 |

## Table 3-4

| CUT No. | AET (C) | PRESSURE (mbar) | CORR. WEIGHT | MOLE-WEIGHT | DEN-SITY | CUMUL. VOLUME% | CUNUL. WEIGHT% | CUMUL. MOLE% |
|---|---|---|---|---|---|---|---|---|
| 6 | 69.2 | 1013.0 | 2.0678 | 74.0 | 637.3 | 2.82 | 2.10 | 6.80 |
| 7 | 98.9 | 1013.0 | 2.8579 | 91.9 | 737.7 | 6.19 | 5.00 | 14.40 |
| 8 | 126.1 | 1013.0 | 4.1783 | 105.0 | 761.4 | 10.96 | 9.24 | 24.10 |
| 9 | 151.3 | 1013.0 | 3.1564 | 119.6 | 767.0 | 14.54 | 12.45 | 30.60 |
| 10 | 174.6 | 1013.0 | 3.3304 | 135.5 | 781.2 | 18.24 | 15.83 | 36.60 |
| 11 | 196.4 | 1013.0 | 3.2152 | 152.1 | 788.8 | 21.79 | 19.09 | 41.80 |
| 12 | 217.3 | 133.0 | 2.6398 | 166.8 | 814.6 | 24.60 | 21.77 | 45.60 |
| 13 | 236.1 | 133.0 | 3.2922 | 177.6 | 821.6 | 28.09 | 25.11 | 50.20 |
| 14 | 253.9 | 133.0 | 3.2779 | 192.0 | 831.5 | 31.51 | 28.44 | 54.30 |
| 13 | 271.1 | 133.0 | 3.4858 | 205.4 | 839.0 | 35.13 | 31.98 | 58.50 |
| 16 | 287.3 | 133.0 | 3.1219 | 218.9 | 845.0 | 38.34 | 35.15 | 62.00 |
| 17 | 303.0 | 133.0 | 3.3203 | 238.1 | 841.9 | 41.77 | 38.52 | 65.40 |
| 18 | 317.0 | 13.3 | 2.0351 | 249.8 | 857.2 | 43.83 | 40.58 | 67.40 |
| 19 | 331.0 | 13.0 | 2.4673 | 260.7 | 856.8 | 46.33 | 43.09 | 69.70 |
| 20 | 344.0 | 13.0 | 3.1851 | 267.7 | 854.9 | 49.57 | 46.32 | 72.60 |
| 21 | 357.0 | 13.0 | 2.9337 | 281.8 | 868.5 | 52.51 | 49.30 | 75.20 |
| 22 | 369.0 | 13.0 | 1.8715 | 298.4 | 869.4 | 54.38 | 51.20 | 76.70 |
| 23 | 381.0 | 13.0 | 2.2685 | 311.4 | 870.5 | 56.65 | 53.50 | 78.5 |
| 24 | 392.0 | 13.0 | 2.6268 | 326.2 | 873.6 | 59.26 | 56.17 | 80.40 |
| 25 | 402.0 | 13.0 | 2.2631 | 347.5 | 876.7 | 61.51 | 58.46 | 82.00 |
| 26 | 413.0 | 2.6 | 2.8756 | 362.8 | 887.6 | 64.32 | 61.38 | 84.00 |
| 27 | 423.0 | 2.6 | 2.7514 | 368.5 | 891.1 | 67.01 | 64.18 | 85.00 |
| 28 | 432.0 | 2.60 | 1.6452 | 383.1 | 896.2 | 68.60 | 65.85 | 86.00 |
| RESIDUE | | | 33.6463 | 630.0 | 931.6 | 100.00 | 100.00 | 99.00 |
| SUM | | | 98.5136 | 241.0 | 856.4 | | | |

| + FRACTION | DENSITY | MOLE WEIGHT | WEIGHT% | MOLE% | VOLUME% |
|---|---|---|---|---|---|
| C7+ | 853.50 | 252.30 | 97.90 | 93.16 | 97.18 |
| C1O+ | 868.00 | 303.10 | 87.55 | 69.35 | 85.46 |
| C15+ | 885.30 | 377.00 | 71.56 | 45.58 | 68.49 |
| C20+ | 898.50 | 452.20 | 56.91 | 30.22 | 53.67 |
| C25+ | 911.60 | 540.40 | 43.83 | 19.48 | 40.74 |
| C29+ | 921.60 | 627.60 | 34.15 | 13.07 | 31.40 |

## Table 3-5

| Cut | Dens.<br>15.0C | Dens.<br>30.0C | Dens.<br>35.0C | Dens.<br>50.0C | MW<br>cryo. | MW<br>gc | Carb.<br>nr. |
|---|---|---|---|---|---|---|---|
| C7- | *637.3 | | | | * | * | |
| C7 | *737.7 | | | | * | * | |
| C8 | *761.4 | | | | * | * | |
| C9 | *767.0 | | | | * | * | |
| C10 | 781.2 | | | | 135.5 | 141.0 | 9.9 |
| C11 | 788.8 | | | | 152.1 | 155.5 | 11.0 |
| C12 | 814.6 | | | | 166.8 | 170.8 | 12.0 |
| C13 | 821.6 | | | | 177.6 | 182.9 | 12.9 |
| C14 | 831.5 | | | | 192.0 | 196.5 | 13.9 |
| C15 | 839.0 | | | | 205.4 | 210.3 | 14.9 |
| C16 | 845.0 | | | | 218.9 | 224.6 | 15.9 |
| C17 | 841.9 | | | | 238.1 | 239.0 | 16.9 |
| C18 | 857.2 | | | | 249.8 | 252.5 | 17.9 |
| C19 | 856.8 | | | | 260.7 | 261.5 | 18.5 |
| C20 | 854.9 | | | | 267.7 | 274.7 | 19.5 |
| C21 | 868.5 | | | | 281.8 | 290.2 | 20.6 |
| C22 | | 859.2 | | | 298.4 | 304.0 | 21.6 |
| C23 | | 860.5 | | | 311.4 | 315.5 | 22.4 |
| C24 | | 863.4 | | | 326.2 | 329.9 | 23.4 |
| C25 | | 866.5 | | | 347.5 | 345.8 | 24.6 |
| C26 | | | 873.8 | | 362.8 | 363.0 | 25.8 |
| C27 | | | 877.4 | | 368.5 | 378.1 | 26.9 |
| C28 | | | | 872.4 | 383.1 | 393.2 | 27.9 |
| C28+ | | | | 909.1 | 630.0 | | |

**Table 3-6**

| CUT NO. | CORR. WEIGHT | MOLE-WEIGHT | DENSITY | N-2 | N-i | N | N+1 | N+2 |
|---|---|---|---|---|---|---|---|---|
| 6 | 2.0678 | 74.0 | 637.3 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 |
| 7 | 2.8579 | 91.9 | 737.7 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 |
| 8 | 4.1783 | 105.0 | 761.4 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 |
| 9 | 3.1564 | 119.6 | 767.0 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 |
| 10 | 3.3304 | 135.5 | 781.2 | 0.1 | 14.3 | 75.5 | 10.1 | 0.0 |
| 11 | 3.2152 | 152.1 | 788.8 | 0.2 | 11.3 | 78.4 | 10.2 | 0.0 |
| 12 | 2.6398 | 166.8 | 814.6 | 0.1 | 7.6 | 77.0 | 15.3 | 0.0 |
| 13 | 3.2922 | 177.6 | 821.6 | 0.2 | 17.7 | 69.7 | 12.4 | 0.0 |
| 14 | 3.2779 | 192.0 | 831.5 | 0.2 | 19.3 | 69.2 | 11.3 | 0.0 |
| 15 | 3.4858 | 205.4 | 839.0 | 0.3 | 20.2 | 68.8 | 10.8 | 0.0 |
| 16 | 3.1219 | 218.9 | 845.0 | 0.2 | 18.8 | 69.7 | 11.3 | 0.0 |
| 17 | 3.3203 | 238.1 | 841.9 | 0.2 | 15.9 | 72.1 | 11.8 | 0.0 |
| 18 | 2.0351 | 249.8 | 857.2 | 0.3 | 17.4 | 72.7 | 9.6 | 0.0 |
| 19 | 2.4673 | 260.7 | 856.8 | 1.9 | 41.2 | 56.6 | 0.4 | 0.0 |
| 20 | 3.1851 | 267.7 | 854.9 | 5.2 | 43.3 | 47.3 | 4.2 | 0.0 |
| 21 | 2.9337 | 281.8 | 868.5 | 4.8 | 35.2 | 53.9 | 6.1 | 0.0 |
| 22 | 1.8715 | 298.4 | 869.4 | 3.7 | 35.7 | 58.1 | 2.5 | 0.0 |
| 23 | 2.2685 | 311.4 | 870.5 | 6.2 | 47.0 | 46.3 | 0.6 | 0.0 |
| 24 | 2.6268 | 326.2 | 873.6 | 5.9 | 44.5 | 49.7 | 0.0 | 0.0 |
| 25 | 2.2631 | 347.5 | 876.7 | 2.6 | 37.8 | 59.6 | 0.0 | 0.0 |
| 26 | 2.8756 | 362.8 | 887.6 | 1.5 | 31.4 | 52.0 | 15.0 | 0.0 |
| 27 | 2.7514 | 368.5 | 891.1 | 3.3 | 23.3 | 57.0 | 14.2 | 2.2 |
| 28 | 1.6452 | 383.1 | 896.2 | 3.1 | 19.3 | 55.5 | 22.1 | 0.0 |
| RESIDUE | 33.6463 | 630.0 | 931.6 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 |
| SUM | 98.5136 | 241.0 | 856.4 | | | | | |

## Table 3-7

| FRACTION | WEIGHT% | VOLUME% | CUMUL. VOLUME% |
|---|---|---|---|
| C7- | 2.10 | 2.82 | 2.82 |
| C7 | 2.90 | 3.37 | 6.19 |
| C8 | 4.25 | 4.77 | 10.96 |
| C9 | 3.69 | 4.12 | 15.08 |
| C10 | 2.92 | 3.20 | 18.28 |
| C11 | 3.11 | 3.38 | 21.66 |
| C12 | 2.99 | 3.15 | 24.81 |
| C13 | 3.39 | 3.53 | 28.34 |
| C14 | 3.44 | 3.54 | 31.88 |
| C16 | 3.41 | 3.48 | 35.36 |
| C16 | 3.13 | 3.17 | 38.53 |
| C17 | 3.19 | 3.25 | 41.78 |
| C18 | 3.10 | 3.10 | 44.87 |
| C19 | 3.16 | 3.15 | 48.03 |
| C20 | 2.66 | 2.66 | 50.69 |
| C21 | 2.56 | 2.52 | 53.22 |
| C22 | 2.52 | 2.49 | 55.70 |
| C23 | 2.36 | 2.32 | 58.02 |
| C24 | 2.25 | 2.21 | 60.23 |
| C25 | 2.38 | 2.32 | 62.55 |
| C26 | 2.22 | 2.14 | 64.69 |
| C27 | 2.35 | 2.26 | 66.95 |
| C28 | 1.32 | 1.27 | 68.22 |
| RESIDUE | 34.58 | 31.78 | 100.00 |
| SUM | 100.00 | 100.00 | |

## Table 3-8

WELL 34/8-1
DATE 01-AUG-86

| | |
|---|---|
| WEIGHT OF OIL (g) | 98.5136 |
| DENSITY (kg/m3) | 847.24 |
| MOLEWEIGHT (STO) | 240.12 |
| LOSS (%) | 0.553 |

COMPOSITION OF LIGHT END.

| GROUP | WEIGHT% | DENSITY | MOLE WEIGHT | MOLE% |
|---|---|---|---|---|
| N2 | 0.000 | 260.0000 | 28.0000 | 0.000 |
| C02 | 0.000 | 420.0000 | 44.0000 | 0.000 |
| Cl | 0.002 | 260.0000 | 16.0000 | 0.030 |
| C2 | 0.009 | 358.0000 | 30.0700 | 0.072 |
| C3 | 0.067 | 507.6000 | 44.0970 | 0.365 |
| iso-C5 | 0.050 | 563.3000 | 58.1240 | 0.206 |
| n-C4 | 0.209 | 584.7000 | 58.1240 | 0.863 |
| neo-C5 | 0.005 | 596.7000 | 72.1510 | 0.017 |
| iso-C5 | 0.222 | 624.6000 | 72.1510 | 0.738 |
| n-C5 | 0.406 | 630.9000 | 72.1510 | 1.350 |
| C6 | 1.129 | 665.9611 | 85.4676 | 3.169 |
| C7 | 2.901 | 737.7272 | 91.8668 | 7.576 |
| C8 | 4.245 | 761.3593 | 104.9967 | 9.700 |
| C9 | 3.687 | 767.0172 | 119.5922 | 7.397 |
| C10+ | 87.067 | 867.1056 | 304.8689 | 68.518 |
| SUM | 99.999 | 847.24 | 240.12 | 100 |

**Table 3-9**

| Component | Wt % | mol % | mol wt. |
|---|---|---|---|
| Nitrogen | 0.10 | 0.29 | |
| Carbon dioxide | 0.59 | 1.05 | |
| Methane | 12.58 | 61.07 | |
| Ethane | 1.77 | 4.58 | |
| Propane | 1.79 | 3.16 | |
| iso-Butane | 0.41 | 0.55 | |
| n-Butane | 1.07 | 1.43 | |
| iso-Pentane | 0.52 | 0.57 | |
| n-Pentane | 0.72 | 0.78 | |
| Hexanes | 1.16 | 1.07 | 84.50 |
| P | 1.06 | 0.96 | |
| N | 0.10 | 0.11 | |
| A | 0.00 | 0.00 | |
| Heptanes | 2.00 | 1.72 | 90.70 |
| P | 0.00 | 0.67 | |
| N | 0.90 | 0.81 | |
| A | 0.24 | 0.24 | |
| Octanes | 2.89 | 2.14 | 105.00 |
| P | 1.17 | 0.80 | |
| N | 1.19 | 0.90 | |
| A | 0.53 | 0.44 | |
| Nonanes | 2.21 | 1.45 | 118.50 |
| P | 1.08 | 0.65 | |
| N | 0.42 | 0.28 | |
| A | 0.71 | 0.52 | |
| Decanes plus | 72.19 | 20.14 | 279 |
| SUM | 100.00 | 100.00 | |
| Average molecular weight: | | | 77.90 |

| | $z_i$ - mol % | $M_i$ | $\rho_i$ | $z_i M_i$ | $z_i M_i / \rho_i$ |
|---|---|---|---|---|---|
| C7 | 1.72 | 90.7 | 0.74 | 156.0 | 210.0 |
| C8 | 2.14 | 105.0 | 0.76 | 224.7 | 296.0 |
| C9 | 1.45 | 118.5 | 0.78 | 171.8 | 220.9 |
| Cl0+ | 20.14 | 279.0 | 0.88 | 5619.1 | 6407.1 |
| Sum / Aver. | 25.45 | 242.5 | 0.87 | 6171.6 | 7134.0 |
| Kw7+= | 11.85 | | | | |

## Table 3-10

RECOMBINED COMPOSITION

| | | | |
|---|---|---|---|
| DATE | 11/11-88 | | |
| WELL | 34/8-3 | | *$R_{sp}$ = 2638 / 1.157 = 2280 Sm$^3$ / Sm$^3$* |
| BOTTLE NO. | A10996 | | |
| TYPE OF SAMPLE | DST2 | | ** Pseudo?? = Lab recomb. Conditions ≠ sep. cond.* |
| TEMP. (C) | 56.3 | | |
| PRESSURE (bara): | 50.3 | *field* | |
| GOR (Sm3/Sm3) | 2385 | (pseudo) *X 2638 Sm$^3$ / Sm$^3$* | |
| OIL | *721 Field* | | |
| DENSITY (kg/m3): | 754.1 | (pseudo) *X sep. oil* | 15 C |
| MOLEWEIGHT | 115.50 | | CRYOSCOPY |

| | GAS PHASE | | LIQUID PHASE | | | RECOMBINED COMPOSITION | | |
|---|---|---|---|---|---|---|---|---|
| FRACTION | WEIGHT% | MOLE% | WEIGHT% | MOLE% | DENSITY | MOLEWG | WEIGHT% | MOLE% |
| N2 | 1.273 | 0.848 | 0.015 | 0.064 | 260.0 | | 0.910 | 0.800 |
| C02 | 2.906 | 1.232 | 0.155 | 0.407 | 420.0 | | 2.111 | 1.181 |
| Cl | 76.952 | 89.496 | 2.259 | 16.263 | 260.0 | | 55.379 | 84.988 |
| C2 | 7.263 | 4.506 | 0.842 | 3.235 | 358.0 | | 5.409 | 4.428 |
| C3 | 4.908 | 2.076 | 1.403 | 3.674 | 507.6 | | 3.895 | 2.174 |
| ISO-C4 | 1.017 | 0.326 | 0.546 | 1.086 | 563.3 | | 0.881 | 0.373 |
| N-C4 | 2.226 | 0.714 | 1.647 | 3.273 | 584.7 | | 2.059 | 0.872 |
| NEO-C5 | 0.013 | 0.003 | 0.015 | 0.024 | 596.7 | | 0.013 | 0.005 |
| ISO-C5 | 0.744 | 0.192 | 1.166 | 1.867 | 624.6 | | 0.866 | 0.295 |
| N-C5 | 0.907 | 0.234 | 1.817 | 2.909 | 630.9 | | 1.170 | 0.399 |
| C-6 | 0.796 | 0.174 | 3.926 | 5.281 | 664.4 | 85.88 | 1.700 | 0.488 |
| C-7 | 0.667 | 0.139 | 8.194 | 10.280 | 736.3 | 92.06 | 2.841 | 0.763 |
| C-8 | 0.287 | 0.053 | 10.280 | 11.277 | 753.4 | 105.29 | 3.173 | 0.743 |
| C-9 | 0.041 | 0.006 | 8.342 | 8.020 | 764.6 | 120.14 | 2.439 | 0.499 |
| C-10+ | 0.000 | 0.000 | 59.391 | 32.341 | 870.5 | 212.11 | 17.154 | 1.991 |

| | GAS PHASE | LIQUID PHASE | RECOM. COMPOSITION |
|---|---|---|---|
| WEIGHT-% C6+ | 1.7917 | 90.13 | 27.3071 |
| NOLE-% C6+ | 0.3715 | 67.20 | 4.4850 |
| MOLEWEIGHT C6+ | 89.9680 | 154.92 | 149.8737 |
| MOLEWEIGHT C1O+ | 156.0000 | 212.11 | 212.1052 |
| MEAN NOLEWEIGHT | 18.6546 | 115.50 | 24.6159 |
| MOLE-DISTRIBUTION | 93.8429 | 6.16 | 100.0000 |
| WEIGHT-DISTRIBUTION | 71.1123 | 28.89 | 100.0000 |
| GAS GRAVITY | 0.6433 | | |
| CRITICAL TEMP(K) | 205.2575 | | |
| CRITICAL PRESS(bara) | 46.4660 | | |
| Z-FACTOR | 0.9179 | | |
| DENSITY (kg/m3) | 37.3054 | | 346.4548 |
| VISCOSITY (mpa*s) | 0.0131 | | |

| | |
|---|---|
| M7+ | 160.8 |
| ρ 7+ | 829.6 |

| FRACTION | GAS PHASE | | | LIQUID PHASE | | | RECOM. COMPOSITION | | |
|---|---|---|---|---|---|---|---|---|---|
| | P | N | A | P | N | A | P | N | A |
| C6 | 97.10 | 2.90 | | 98.50 | 1.50 | | 98.00 | 2.00 | |
| C7 | 37.50 | 47.20 | 15.40 | 48.50 | 40.80 | 10.60 | 46.70 | 41.90 | 11.40 |
| C8 | 32.50 | 43.70 | 23.70 | 48.20 | 35.80 | 16.00 | 47.20 | 36.30 | 16.50 |
| C9 | 84.60 | 13.10 | 2.10 | 56.70 | 20.30 | 23.00 | 57.00 | 20.20 | 22.80 |

## Table 3-11

| | |
|---|---|
| DATE | 11/11-88 |
| WELL | 34/8-3 |
| BOTTLE NO. | 23 |
| TYPE OF SAMPLE | KOND . DST2 |
| TEMP. (C) | 56.30 |
| PRESSURE (bara): | 50.30 |
| GOR (Sm3/5m3) | 44.40 |

<u>OIL</u>

| | | |
|---|---|---|
| DENSITY (kg/m3): | 783.6 | 15 C |
| NOLEWEIGHT | 146 | CRYOSCOPY |

| | GAS PHASE | | LIQUID PHASE | | | RECOMBINED COMPOSITION | | |
|---|---|---|---|---|---|---|---|---|
| FRACTION | WEIGHT% | MOLE% | WEIGHT% | MOLE% | DENSITY | MOLEWG | WEIGHT% | MOLE% |
| N2 | 0.255 | 0.249 | 0.000 | 0.000 | 260.00 | | 0.015 | 0.064 |
| C02 | 2.560 | 1.588 | 0.000 | 0.000 | 420.00 | | 0.155 | 0.408 |
| CI | 37.202 | 63.308 | 0.003 | 0.027 | 260.00 | | 2.259 | 16.268 |
| C2 | 13.257 | 12.034 | 0.041 | 0.199 | 358.00 | | 0.842 | 3.236 |
| C3 | 17.650 | 10.924 | 0.354 | 1.172 | 507.60 | | 1.403 | 3.675 |
| ISO-C4 | 4.582 | 2.152 | 0.286 | 0.718 | 563.30 | | 0.546 | 1.086 |
| N-C4 | 10.522 | 4.941 | 1.074 | 2.698 | 584.70 | | 1.647 | 3.274 |
| NEO-C5 | 0.063 | 0.024 | 0.012 | 0.024 | 596.70 | | 0.015 | 0.024 |
| ISO-C5 | 3.397 | 1.285 | 1.022 | 2.068 | 624.60 | | 1.166 | 1.867 |
| N-C5 | 3.913 | 1.480 | 1.682 | 3.404 | 630.90 | | 1.817 | 2.910 |
| C-6 | 3.066 | 0.978 | 3.982 | 6.768 | 664.40 | 85.89 | 3.926 | 5.282 |
| C-7 | 2.505 | 0.767 | 8.561 | 13.568 | 736.00 | 92.12 | 8.194 | 10.283 |
| C-8 | 0.938 | 0.250 | 10.883 | 15.088 | 753.40 | 105.31 | 10.280 | 11.280 |
| C-9 | 0.091 | 0.020 | 8.875 | 10.785 | 764.60 | 120.14 | 8.342 | 8.022 |
| C-10+ | 0.000 | 0.000 | 63.225 | 43.479 | 827.00 | 212.30 | 59.391 | 32.321 |

| | GAS PHASE | LIQUID PHASE | RECOM. COMPOSITION |
|---|---|---|---|
| WEIGHT-% C6+ | 6.5996 | 9S.S3 | 90.1340 |
| MOLE-% C6+ | 2.0149 | 89.69 | 67.1880 |
| MOLEWEIGHT C6+ | 89.4029 | 155.50 | 154.9925 |
| MOLEWEIGHT C10+ | 156.0000 | 212.30 | 212.3037 |
| MEAN MOLEWEIGHT | 27.2958 | 146.00 | 115.5350 |
| MOLE-DISTRIBUTION | 25.6598 | 74.34 | 100.0000 |
| WEIGHT-DISTRIBUTION | 6.0620 | 93.94 | 100.0000 |
| GAS GRAVITY | 0.9412 | | |
| CRITICAL TEMP(K) | 256.3946 | | |
| CRITICAL PRESS(bara) | 45.4203 | | |
| Z-FACTOR | 0.8095 | | |
| DENSITY (kg/m3) | 61.8986 | | 734.2313 |
| VISCOSITY (mpa*s) | 0.0125 | | |

| FRACTION GAS | GAS PHASE | | | LIQUID PHASE | | | RECOM. COMPOSITION. | | |
|---|---|---|---|---|---|---|---|---|---|
| | P | N | A | P | N | A | P | N | A |
| C6 | 97.0 | 3.0 | | 98.5 | 1.5 | | 98.5 | 1.5 | |
| C7 | 36.3 | 49.2 | 14.5 | 48.7 | 40.7 | 10.6 | 48.5 | 40.8 | 10.6 |
| C8 | 30.7 | 55.2 | 14.1 | 48.3 | 35.7 | 16.0 | 48.2 | 35.8 | 16.0 |
| C9 | 58.3 | 32.7 | 9.0 | 56.7 | 20.3 | 23.0 | 56.7 | 20.3 | 23.0 |

## Table 3-12

### TEST SEPARATOR GOR CORRECTION FOR WELLSTREAM RECOMBINATION CALCULATIONS

$$(R_{sp})_{lab} = (R_{sp})_{field} \frac{\sqrt{(Z_g)_{field}\,(\gamma_g)_{field}}}{\sqrt{(Z_g)_{lab}\,(\gamma_g)_{lab}}} \frac{(p_{sc})_{field}}{(p_{sc})_{lab}}$$

$$F_{gsp} = \frac{1}{1 + 23.68 \dfrac{\rho_{osp}}{M_{osp}\ (R_{sp})_{lab}}}$$

$$z_i = F_{gsp}\ y_i + (1 - F_{gsp})\ x_i$$

$(R_{sp})_{field}$ = separator gas-oil ratio based on rates calculated in the field, $Sm^3/sep.m^3$

$(R_{sp})_{lab}$ = corrected separator GOR at laboratory conditions, used to determine the physical and mathematical recombination molar ratio $F_{gsp}$

$(Z_g)_{field}$ = separator gas Z-factor used in field calculation of gas rate

$(Z_g)_{lab}$ = laboratory (true) separator gas Z-factor determined in the laboratory at conditions during gas metering

$(\gamma_g)_{field}$ = separator gas gravity used in field calculations of gas rate

$(\gamma_g)_{lab}$ = separator gas gravity based on measured composition or direct measurement

$(\rho_{osp})$ = separator oil density at separator conditions during sampling, $kg/m^3$

$(M_{osp})$ = separator oil molecular weight

$F_{gsp}$ = mole fraction of total wellstream leaving the separator in the gas stream

$y_i$ = laboratory measured separator gas molar composition

$x_i$ = laboratory measured separator oil molar composition

**$z_i$ = wellstream molar composition**

**Table 3-13**

## THREE STAGE SEPARATOR TEST OF RESERVOIR FLUID TO STOCK TANK CONDITIONS

| Stage | Pressure bar | Temp. °C | Evolved gas 3) $Sm^3/m^3$ | $R_s$ 3) $Sm^3/m^3$ | $B_o$ 4) $m^3/m^3$ | Density of st. tank oil $kg/m^3$ | Gas gravity Air=1 |
|---|---|---|---|---|---|---|---|
| | 424.5 1) | 114.0 2) | | 221.8 | 1.640 | | 0.659 |
| 1 | 70.0 | 50.0 | 183.6 | 38.2 | 1.140 | | 0.628 |
| 2 | 30.0 | 50.0 | 20.1 | 18.1 | 1.104 | | 0.662 |
| 3 | atm | 15.0 | 18.1 | 0.0 | 1.000 | 851.8 | 0.974 |
| | | | | | | 34.4 API | |

1 Bubble point pressure at reservoir temperature

2 Reservoir temperature

3 Standard $m^3$ gas per $m^3$ stock tank oil

4 $m^3$ liquid at indicated pressure and temperature per $m^3$ stock tank oil

**Table 3-14**

PRESSURE-VOLUME RELATION OF RESERVOIR FLUID

| Pressure | Relative volume $V/V_{bp}$ | Isothermal compressibility $bar^{-1}$ | "Y" |
|---|---|---|---|
| 548.7 | 0.9737 | 1.78E-04 | |
| 525.9 | 0.9781 | 1.91E-04 | |
| 501.7 | 0.9824 | 2.05E-04 | |
| 478.3 | 0.9874 | 2.19E-04 | |
| 452.6 | 0.9934 | 2.34E-04 | |
| 430.5 | 0.9985 | 2.46E-04 | |
| 424.5 | 1.0000 | 2.50E-04 | |
| 412.8 | 1.0063 | | 4.520 |
| 391.4 | 1.0197 | | 4.294 |
| 368.3 | 1.0363 | | 4.200 |
| 338.6 | 1.0622 | | 4.078 |
| 306.4 | 1.0977 | | 3.944 |
| 276.1 | 1.1416 | | 3.796 |
| 239.3 | 1.2149 | | 3.602 |
| 202.7 | 1.3219 | | 3.399 |
| 155.9 | 1.5512 | | 3.126 |
| 116.4 | 1.9184 | | 2.882 |
| 85.9 | 2.4620 | | 2.696 |

Best fit V equation above boiling point
$V_{rel} = 1.1617 - 5.120 \text{ X } 10^{-4}\ p + 3.091 \text{ X } 10^{-7}\ p^{2}$

Best fit Y equation
$Y = 2.286 + 0.532 \text{ X } 10^{-2}\ p$

**Table 3-15**

T = 112 °C

| Pressure bara | Relative volume | Rel. (1) liquid % | Volumetric (2) Z-factor | Compositional (3) Z-factor |
|---|---|---|---|---|
| 532.42 | 0.909 | | 1.2172 | 1.2171 |
| 511.54 | 0.924 | | 1.1887 | 1.1927 |
| 491.25 | 0.940 | | 1.1612 | 1.1693 |
| 470.57 | 0.958 | | 1.1334 | 1.1459 |
| 451.48 | 0.976 | | 1.1080 | 1.1247 |
| 435.89 | 0.992 | | 1.0873 | 1.1076 |
| 432.39 | 0.998 | | 1.0834 | 1.1038 |
| 430.39 | 0.999 | | 1.0801 | 1.1017 |
| Pd - 430.00 | 1.000 | Trace | 1.0788 | 1.1007 |
| 422.99 | 1.007 | 0.045 | 1.0707 | |
| 416.50 | 1.015 | 0.218 | 1.0633 | |
| 401.50 | 1.035 | 0.787 | 1.0448 | |
| 381.61 | 1.065 | 1.606 | 1.0215 | |
| 361.71 | 1.099 | 2.550 | 0.9994 | |
| 341.51 | 1.139 | 3.460 | 0.9778 | |
| 321.41 | 1.185 | 4.354 | 0.9574 | |
| 301.51 | 1.239 | 5.507 | 0.9391 | |
| 281.41 | 1.304 | 6.714 | 0.9225 | |
| 261.50 | 1.380 | 7.528 | 0.9074 | |
| 241.79 | 1.473 | 8.179 | 0.8951 | |
| 221.79 | 1.587 | 8.848 | 0.8850 | |
| 201.47 | 1.729 | 9.230 | 0.8761 | |
| 181.46 | 1.909 | 9.701 | 0.8711 | |
| 161.54 | 2.139 | 9.912 | 0.8688 | |
| 141.43 | 2.443 | 10.076 | 0.8688 | |
| 121.31 | 2.857 | 10.097 | 0.8715 | |
| 101.69 | 3.433 | 9.972 | 0.8777 | |
| 81.16 | 4.343 | 9.726 | 0.8863 | |
| 63.14 | 5.656 | 9.395 | 0.8980 | |

(1). Retrograde liquid deposit in volume % of sample volume at dewpoint.

(2). Z = pV/nRT. Not corrected for liquid deposit below the dewpoint.

(3). Z-factor from the recombined composition in table 4 by the Dranchuc correlation

**Table 3-16**

# DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT 114 °C

| Pressure (bar) | 3) Oil Formation Volume Factor $B_o$ | 4) Solution Gas-Oil Ratio $R_s$ ($Sm^3/Sm^3$) | 5) Gas Formation Volume Factor $B_g$ ($m^3/Sm^3$) | Density of saturated oil ($kg/m^3$) | 2) $B_t$ ($m^3/Sm^3$) |
|---|---|---|---|---|---|
| 548.7 | 1.691 | | | 643.40 | |
| 525.9 | 1.698 | | | 640.50 | |
| 501.7 | 1.714 | | | 634.40 | |
| 452.6 | 1.725 | | | 630.60 | |
| 430.5 | 1.734 | | | 627.40 | |
| 424.5 | 1.736 | 250.50 | | 626.40 | 1) 1.736 |
| 391.3 | 1.650 | 217.10 | 3.76E-03 | 643.20 | 1.775 |
| 345.3 | 1.557 | 180.90 | 4.00E-03 | 662.50 | 1.835 |
| 300.7 | 1.484 | 151.20 | 4.43E-03 | 679.00 | 1.924 |
| 252.5 | 1.415 | 123.60 | 5.17E-03 | 696.40 | 2.071 |
| 203.1 | 1.354 | 98.30 | 6.28E-03 | 712.80 | 2.309 |
| 153.1 | 1.297 | 74.60 | 8.24E-03 | 729.50 | 2.747 |
| 101.8 | 1.242 | 51.50 | 1.256E-02 | 746.50 | 3.741 |
| 49.7 | 1.187 | 29.10 | 2.649E-02 | 764.80 | 7.050 |
| 14.2 | 1.140 | 12.60 | 9.664E-02 | 781.60 | 24.129 |
| 1.0 | 1.091 | | | 787.40 | |

Density of residual oil at 15 °C: 859.0 $kg/m^3$

1) Density at bubble point from single flash: 634.5 $kg/m^3$
2) Volume of oil and liberated gas at p and tivolume of residual oil
3) $m^3$ liquid at indicated pressure per $m^3$ residual oil
4) Standard $m^3$ gas per $m^3$ residual oil
5) $m^3$ gas at indicated pressure per $m^3$ gas at standard condition

$B_o$, see fig. 8
$R_s$, see fig. 9
$B_g$, see fig. 10
Density of saturated oil, see fig. 14

NORSK HYDRO A/S
Well: 34/8-3A DST1A

**Table 3-17**

## DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT 114 °C

(Gas properties calculated from molecular composition)

| Pressure (bar) | 1) Gas viscosity (mPa/s) | Gas gravity (Air = 1) | Compressibility factor, Z | Molecular wieght |
|---|---|---|---|---|
| 391.3 | 0.0256 | 0.654 | 1.0697 | 18.94 |
| 345.3 | 0.0242 | 0.662 | 1.0238 | 19.18 |
| 300.7 | 0.0226 | 0.661 | 0.9844 | 19.16 |
| 252.5 | 0.0208 | 0.657 | 0.9488 | 19.02 |
| 203.1 | 0.0190 | 0.656 | 0.9234 | 19.00 |
| 153.1 | 0.0174 | 0.654 | 0.9135 | 18.94 |
| 101.9 | 0.0159 | 0.665 | 0.9196 | 19.27 |
| 49.7 | 0.0146 | 0.702 | 0.9463 | 20.33 |
| 14.2 | 0.0135 | 0.835 | 0.9763 | 24.18 |
| 1.0 | - | 2.069 | - | 59.93 |

1) For the calculation ref. page 46
Gas viscosity, see fig. 11
Gas gravity, see fig. 12
Compressibility factor, see fig. 13

**Table 3-18**

## DIFFERENTIAL LIBERATION OF RESERVOIR FLUID AT 114.0 °C

MOLECULAR COMPOSITION OF LIBERATED GASES weight % (wt.%) and mol%

| Pressure/bar | 391.3 | | | 345.3 | | | 300.7 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Wt% | mol % | Mol. weight | Wt% | mol % | Mol. weight | Wt% | mol % | Mol. weight |
| Nitrogen | 0.91 | 0.61 | | 0.99 | 0.68 | | 0.89 | 0.61 | |
| Carbon dioxide | 2.91 | 1.25 | | 2.87 | 1.25 | | 2.87 | 1.25 | |
| Methane | 75.19 | 88.79 | | 73.92 | 88.40 | | 74.19 | 88.61 | |
| Ethane | 7.45 | 4.69 | | 7.26 | 4.64 | | 7.28 | 4.64 | |
| Propane | 5.67 | 2.44 | | 5.84 | 2.54 | | 5.57 | 2.42 | |
| iso-Butane | 1.17 | 0.38 | | 1.13 | 0.37 | | 1.10 | 0.36 | |
| n-Butane | 2.60 | 0.85 | | 2.57 | 0.85 | | 2.50 | 0.82 | |
| i so-Pentane | 0.99 | 0.26 | | 1.01 | 0.27 | | 0.98 | 0.26 | |
| n-Pentane | 1.18 | 0.31 | | 1.28 | 0.34 | | 1.22 | 0.32 | |
| Hexanes | 1.07 | 0.24 | 84.2 | 1.42 | 0.32 | 84.3 | 1.35 | 0.31 | 84.3 |
| Heptanes | 0.71 | 0.15 | 90.3 | 1.30 | 0.27 | 90.8 | 1.34 | 0.28 | 91.1 |
| Octanes | 0.15 | 0.03 | 105.1 | 0.41 | 0.07 | 105.1 | 0.61 | 0.11 | 105.1 |
| Nonanes | 0.00 | 0.00 | | 0.00 | 0.00 | | 0.08 | 0.01 | 118.2 |
| Decanes-plus | 0.00 | 0.00 | | 0.00 | 0.00 | | 0.02 | 0.002 | 156 |
| Sum | 100.00 | 100.00 | | 100.00 | 100.00 | | 100.00 | 100.002 | |
| Average molwt. | | | 18.94 | | | 19.18 | | | 19.16 |

## Table 3-19

### VISCOSITY OF RESERVOIR FLUID AT 114 °C

| | Pressure bar | Viscosity mPa.s |
|---|---|---|
| | 530.0 | 0.321 |
| | 510.5 | 0.315 |
| | 491.5 | 0.310 |
| | 471.5 | 0.306 |
| | 451.5 | 0.300 |
| Pb | 431.5 | 0.293 |
| | 424.5 | 0.292 |
| | 394.5 | 0.320 |
| | 371.3 | 0.340 |
| | 341.9 | 0.367 |
| | 299.4 | 0.418 |
| | 253.7 | 0.484 |
| | 202.3 | 0.580 |
| | 152.1 | 0.685 |
| | 101.5 | 0.829 |
| | 49.5 | 1.045 |
| | 12.1 | 1.397 |
| | 1.0 | 1.564 |

## Table 3-20

## Depletion study of reservoir fluid at 112 °C

| | Pressure bara | Retrograde liquid deposit vol % of dewpoint vol. | Cumulative produced fluid mole % of initial fluid | Z-factor, volumetric Z=pV/nRT | Z-factor compositional (D.P.R.) |
|---|---|---|---|---|---|
| Pd | 430.0 | 0.00 | 0.00 | 1.080 | 1.102 |
| | 407.7 | 0.67 | 2.71 | 1.103 | 1.074 |
| | 372.2 | 2.43 | 7.07 | 1.033 | 1.033 |
| | 321.6 | 4.86 | 14.72 | 0.979 | 0.982 |
| | 271.7 | 6.75 | 24.42 | 0.943 | 0.942 |
| | 220.8 | 7.82 | 36.06 | 0.912 | 0.913 |
| | 170.3 | 8.22 | 49.13 | 0.908 | 0.903 |
| | 121.2 | 8.04 | 62.63 | 0.917 | 0.907 |
| | 62.3 | 7.40 | 79.16 | 0.953 | 0.943 |

| | | | |
|---|---|---|---|
| Mass balance : | | Initial fluid amount, moles : | 4.513 * |
| | - | Residual fluid amount, moles : | 0.835 ** |
| | = | Produced fluid amount, moles : | 3.678 |
| | | Recovered fluid amount, moles: | 3.572 *** |
| Recovery % : | | 3.572 / 3.678 * 100% : | 97.12% |

* Initial amount of fluid in the condensate cell at 112 °C and 430 bar.

** Residual fluid amount in the condensate cell at 112 °C and 62.3 bar.

*** Total recovery of gas and condensate at standard conditions.

**Table 3-21**

Composition (mole %) of produced gas from depletion study at 112 °C

| Pressure bara | 407.7 | 372.2 | 321.6 | 271.7 | 220.8 | 170.3 | 121.2 | 62.3 |
|---|---|---|---|---|---|---|---|---|
| N2 | 0.819 | 0.817 | 0.845 | 0.799 | 0.867 | 0.867 | 0.811 | 0.836 |
| CO2 | 1.212 | 1.210 | 1.260 | 1.250 | 1.242 | 1.250 | 1.198 | 1.262 |
| C1 | 85.484 | 85.435 | 85.920 | 86.687 | 87.166 | 87.816 | 88.067 | 88.640 |
| C2 | 4.499 | 4.494 | 4.483 | 4.491 | 4.490 | 4.494 | 4.357 | 4.603 |
| C3 | 2.214 | 2.214 | 2.196 | 2.183 | 2.172 | 2.135 | 2.061 | 2.099 |
| iso-C4 | 0.381 | 0.382 | 0.378 | 0.373 | 0.370 | 0.355 | 0.361 | 0.325 |
| n-C4 | 0.887 | 0.892 | 0.879 | 0.863 | 0.854 | 0.810 | 0.859 | 0.729 |
| neo-C5 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.004 | 0.003 |
| iso-C5 | 0.298 | 0.301 | 0.295 | 0.286 | 0.282 | 0.258 | 0.308 | 0.235 |
| n-C5 | 0.396 | 0.402 | 0.393 | 0.379 | 0.375 | 0.337 | 0.427 | 0.298 |
| C6 | 0.468 | 0.482 | 0.470 | 0.439 | 0.435 | 0.373 | 0.493 | 0.292 |
| C7 | 0.670 | 0.703 | 0.678 | 0.604 | 0.552 | 0.494 | 0.472 | 0.280 |
| C8 | 0.606 | 0.654 | 0.620 | 0.526 | 0.423 | 0.365 | 0.289 | 0.176 |
| C9 | 0.371 | 0.410 | 0.379 | 0.306 | 0.204 | 0.161 | 0.108 | 0.075 |
| C10+ | 1.692 | 1.599 | 1.198 | 0.809 | 0.563 | 0.282 | 0.186 | 0.144 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Moleweight | 22.80 | 22.80 | 22.10 | 21.30 | 20.70 | 20.10 | 19.90 | 19.30 |
| Gravity (air=1) | 0.7857 | 0.7855 | 0.7629 | 0.7348 | 0.7143 | 0.6920 | 0.6866 | 0.6663 |
| Viscosity (cP) | 0.0317 | 0.0299 | 0.0265 | 0.0234 | 0.0206 | 0.0183 | 0.0165 | 0.0150 |
| C7+ | 3.339 | 3.366 | 2.875 | 2.245 | 1.742 | 1.302 | 1.055 | 0.675 |

**Table 3-22**

**Table 3-23**

$$K_i\ p_{sp} = a + c\ F_i$$

$$F_i = b_i\ (1/T_{bi} - 1/T_{sp})\ ;\ T(^oR)$$

| Component | | $b_i$ cycle-$^o$R | $T_{bi}$ $^o$R |
|---|---|---|---|
| Nitrogen | $N_2$ | 470 | 109 |
| Carbon Dioxide | $CO_2$ | 652 | 194 |
| Hydrogen Sulfide | $H_2S$ | 1136 | 331 |
| Methane | $C_1$ | 300 | 94 |
| Ethane | $C_2$ | 1145 | 303 |
| Propane | $C_3$ | 1799 | 416 |
| i-Butane | $iC_4$ | 2037 | 471 |
| n-Butane | $nC_4$ | 2153 | 491 |
| i-Pentane | $iC_5$ | 2368 | 542 |
| n-Pentane | $nC_5$ | 2480 | 557 |
| Hexanes (lumped*) | $C_{6s}$ | 2738 | 610 |
| n-Hexane | $nC_6$ | 2780 | 616 |
| n-Heptane | $nC_7$ | 3068 | 669 |
| n-Octane | $nC_8$ | 3335 | 718 |
| n-Nonane | $nC_9$ | 3590 | 763 |
| n-Decane | $nC_{10}$ | 3828 | 805 |

Heptanes-plus:

$$n_{7+} = 7.3 + 0.0075\ T_{sp}(^oF) + 0.0016\ p_{sp}(psia)$$

$$b_{7+} = 1013 + 324\ n_{7+} - 4.256(n_{7+})^2$$

$$T_{b7+} = 301 + 59.85\ n_{7+} - 0.971(n_{7+})^2$$

* Lumped hexanes include 25% 2-methyl pentane, 25% 3-methyl pentane, and 50% normal hexane.

**Table 3-24**

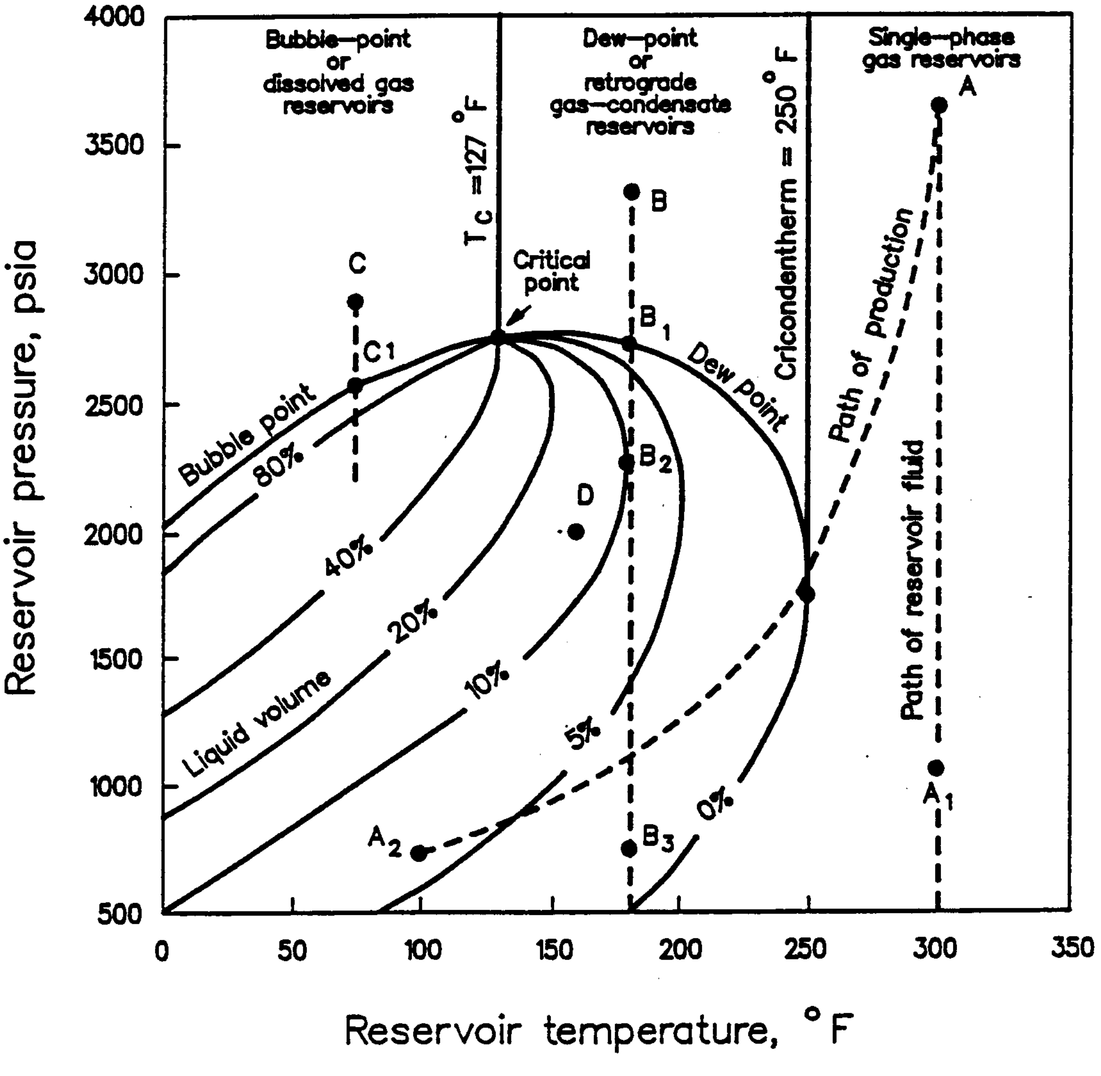

Bubble-point or dissolved gas reservoirs
Dew-point or retrograde gas-condensate reservoirs
Single-phase gas reservoirs
T c =127 °F
Cricondentherm = 250 °F
Critical point
Bubble point
Dew point
Liquid volume
80%
40%
20%
10%
5%
0%
A
A1
A2
B
B1
B2
B3
C
C1
D
Path of production
Path of reservoir fluid
Reservoir pressure, psia
4000
3500
3000
2500
2000
1500
1000
500
Reservoir temperature, °F
0
50
100
150
200
250
300
350

**Figure 3-1**

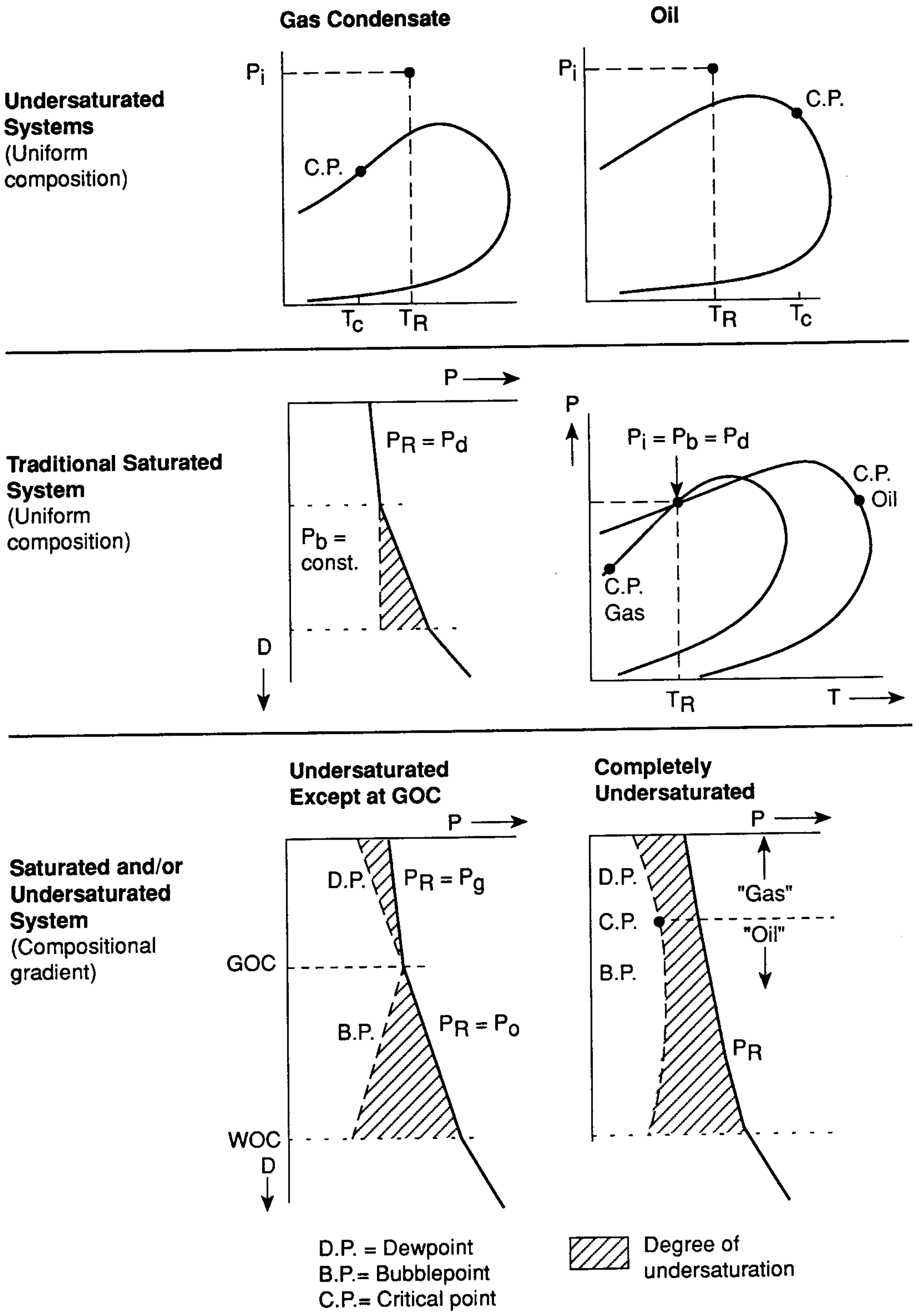

Gas Condensate
Oil
Undersaturated Systems
(Uniform composition)
$P_i$
C.P.
$T_c$
$T_R$
Traditional Saturated System
(Uniform composition)
P →
$P_R = P_d$
$P_b$ = const.
D
P
$P_i = P_b = P_d$
C.P. Oil
C.P. Gas
T →
Saturated and/or Undersaturated System
(Compositional gradient)
Undersaturated Except at GOC
Completely Undersaturated
D.P.
$P_R = P_g$
GOC
B.P.
$P_R = P_o$
WOC
"Gas"
"Oil"
$P_R$
D.P. = Dewpoint
B.P.= Bubblepoint
C.P.= Critical point
Degree of undersaturation

Figure 3-2

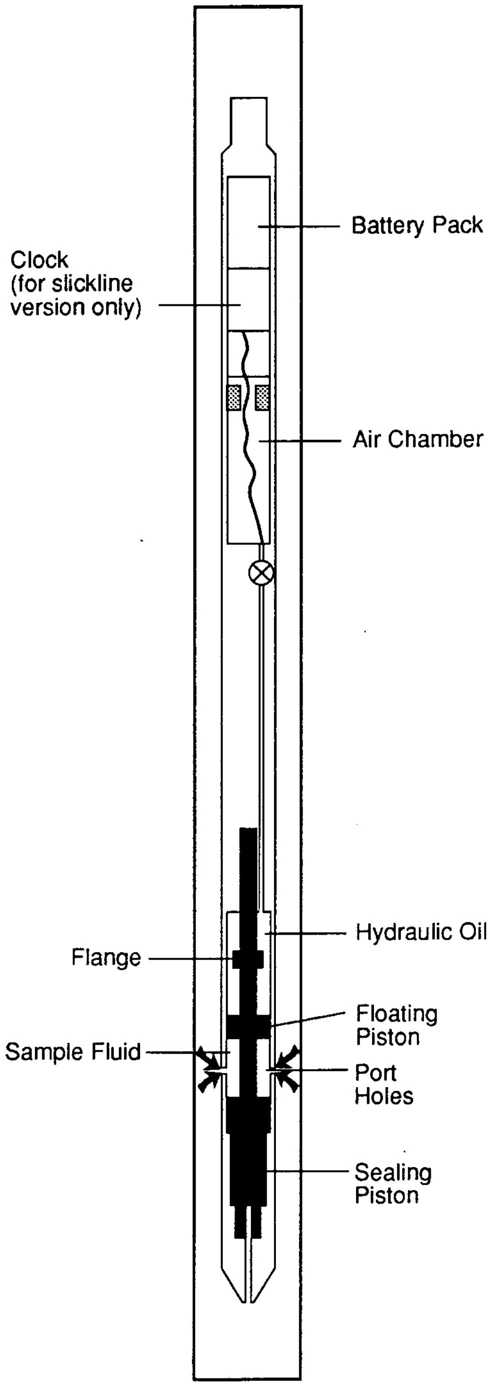

Battery Pack
Clock (for slickline version only)
Air Chamber
Hydraulic Oil
Flange
Floating Piston
Sample Fluid
Port Holes
Sealing Piston

**Figure 3-3**

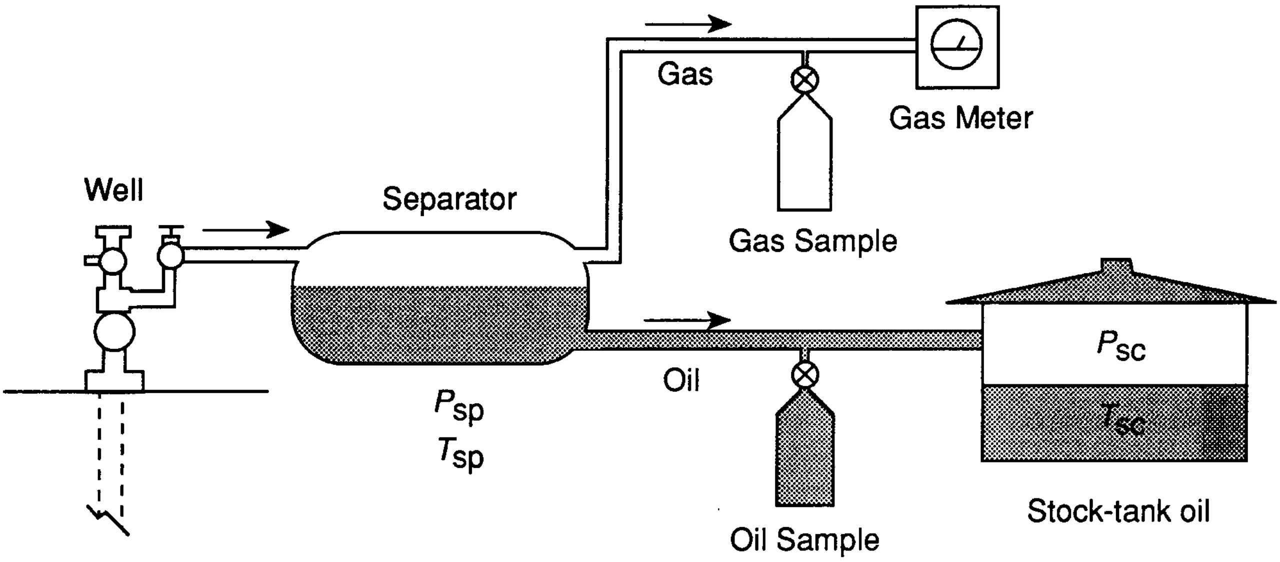

Gas
Gas Meter
Well
Separator
Gas Sample
$P_{sc}$
$T_{sc}$
Oil
$P_{sp}$
$T_{sp}$
Stock-tank oil
Oil Sample

**Figure 3-4**

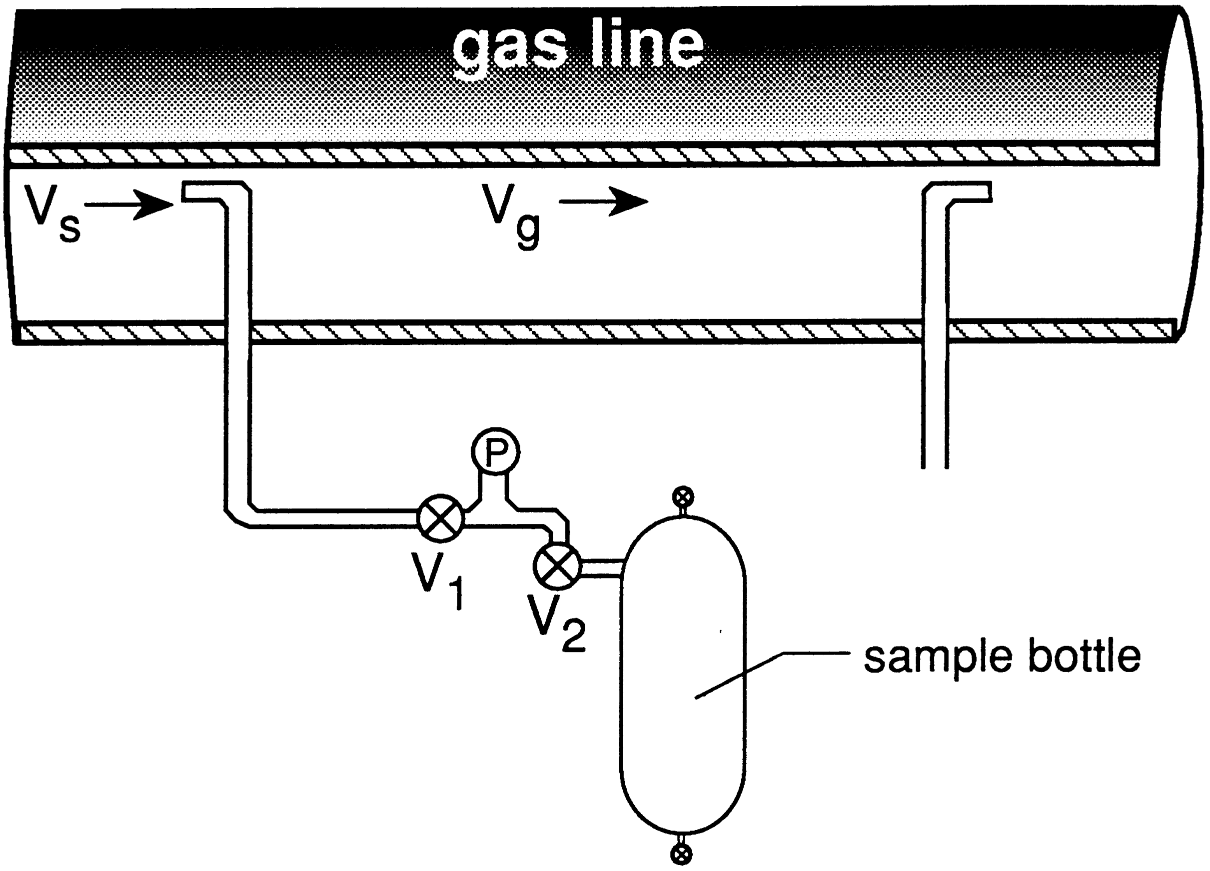


**Figure 3-5**

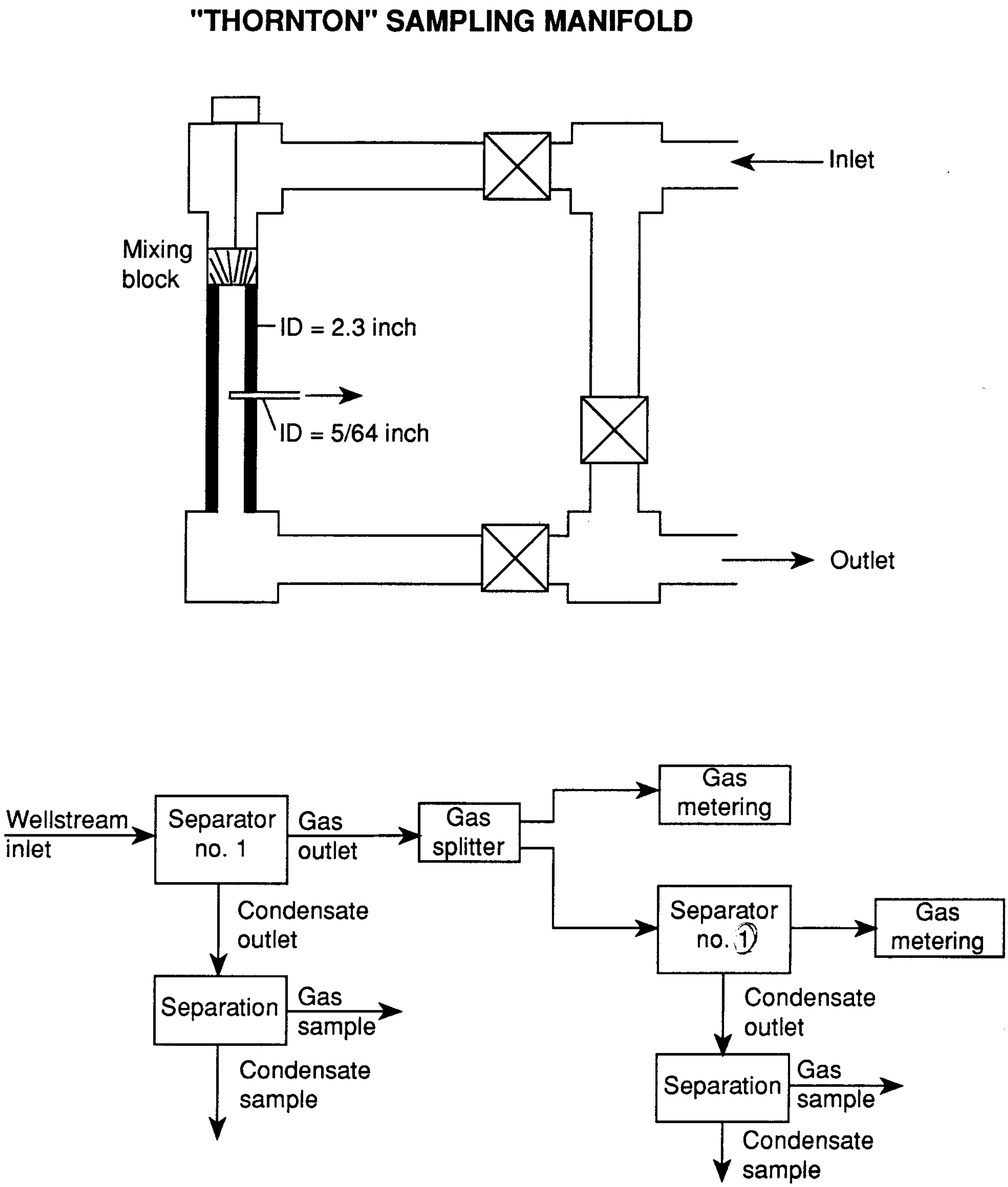

"THORNTON" SAMPLING MANIFOLD
Inlet
Mixing block
ID = 2.3 inch
ID = 5/64 inch
Outlet
Wellstream inlet
Separator no. 1
Gas outlet
Gas splitter
Gas metering
Condensate outlet
Separator no. 1
Gas metering
Separation
Gas sample
Condensate sample
Condensate outlet
Separation
Gas sample
Condensate sample

**Figure 3-6**

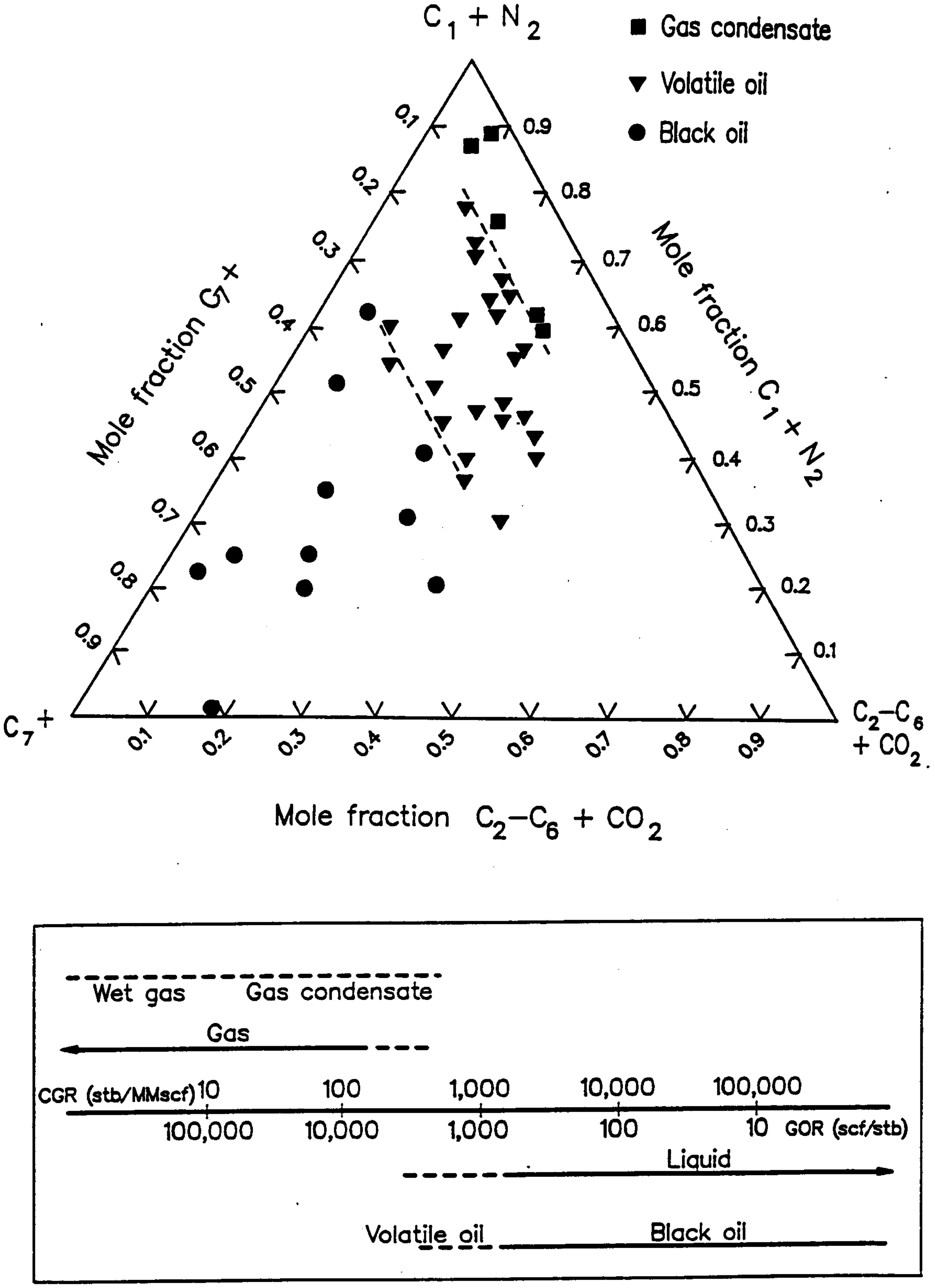

C1 + N2
■ Gas condensate
▼ Volatile oil
● Black oil
Mole fraction C7+
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Mole fraction C1 + N2
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
C7+
C2–C6 + CO2
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
Mole fraction C2–C6 + CO2
Wet gas
Gas condensate
Gas
CGR (stb/MMscf)
10
100
1,000
10,000
100,000
100,000
10,000
1,000
100
10
GOR (scf/stb)
Liquid
Volatile oil
Black oil

**Figure 3-7**

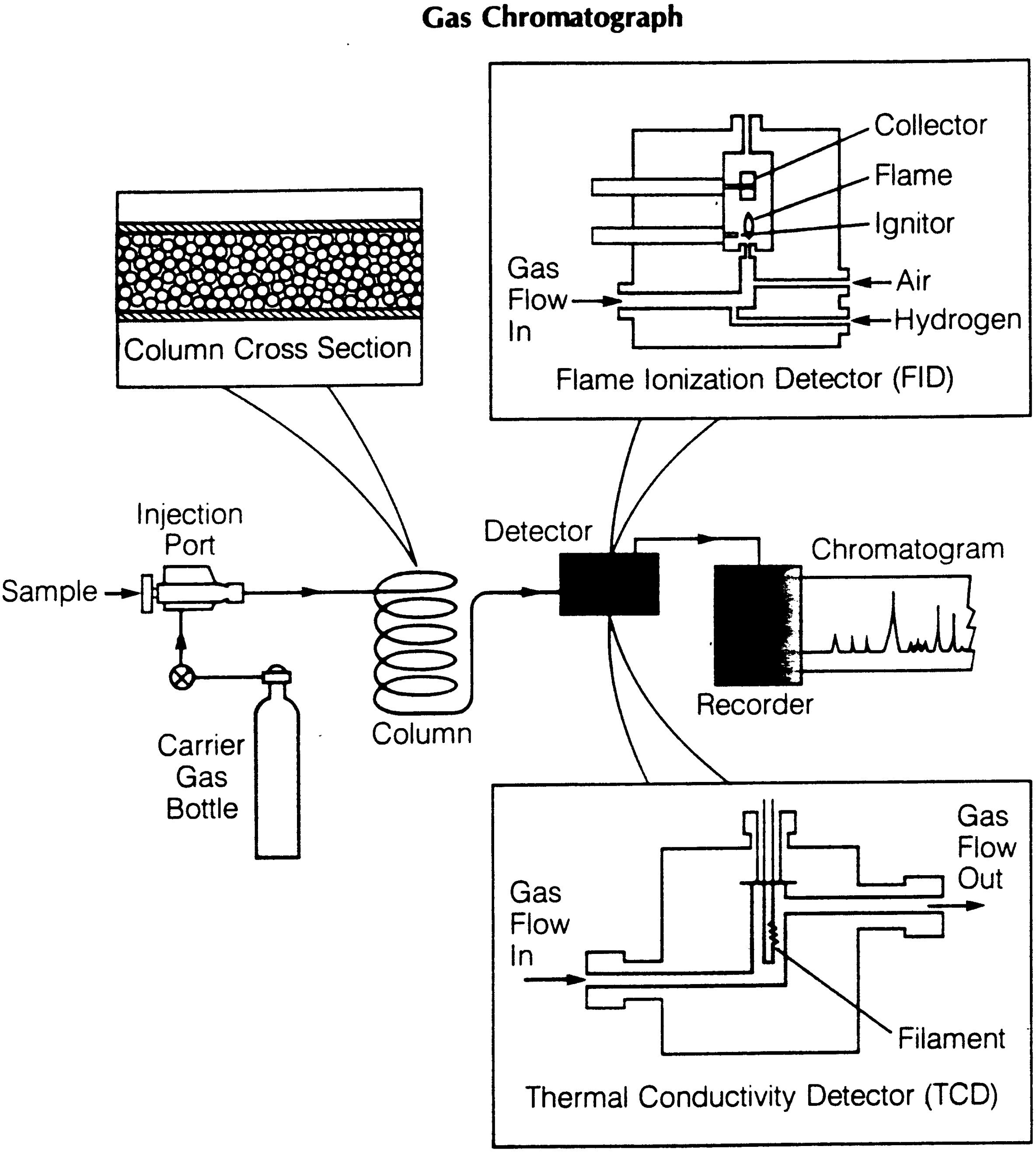

Gas Chromatograph
Column Cross Section
Collector
Flame
Ignitor
Gas
Flow
In
Air
Hydrogen
Flame Ionization Detector (FID)
Injection
Port
Sample
Detector
Chromatogram
Column
Recorder
Carrier
Gas
Bottle
Gas
Flow
Out
Gas
Flow
In
Filament
Thermal Conductivity Detector (TCD)

**Figure 3-8**

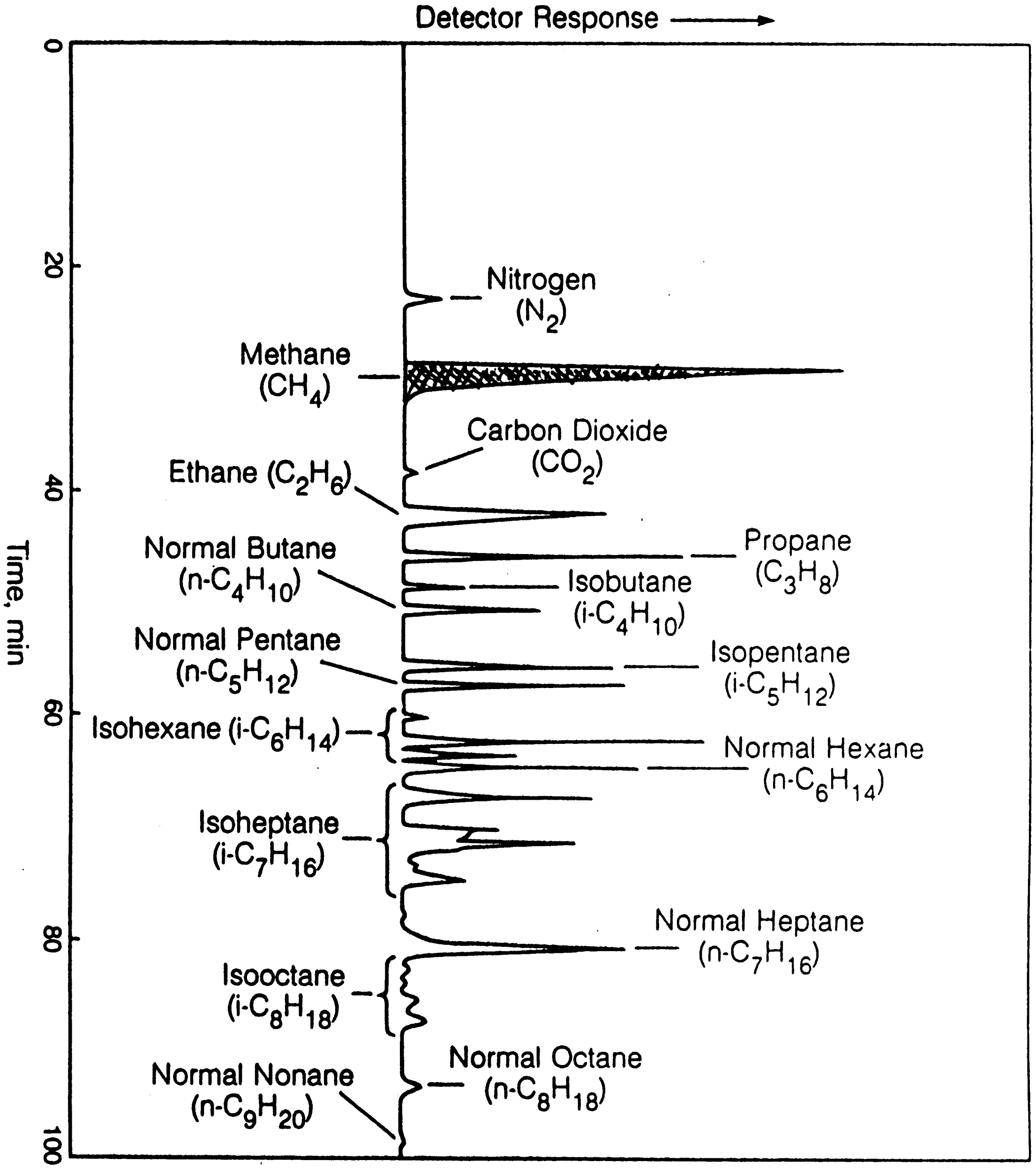

Detector Response
Time, min
0
20
40
60
80
100
Nitrogen ($N_2$)
Methane ($CH_4$)
Carbon Dioxide ($CO_2$)
Ethane ($C_2H_6$)
Propane ($C_3H_8$)
Normal Butane ($n\text{-}C_4H_{10}$)
Isobutane ($i\text{-}C_4H_{10}$)
Normal Pentane ($n\text{-}C_5H_{12}$)
Isopentane ($i\text{-}C_5H_{12}$)
Isohexane ($i\text{-}C_6H_{14}$)
Normal Hexane ($n\text{-}C_6H_{14}$)
Isoheptane ($i\text{-}C_7H_{16}$)
Normal Heptane ($n\text{-}C_7H_{16}$)
Isooctane ($i\text{-}C_8H_{18}$)
Normal Octane ($n\text{-}C_8H_{18}$)
Normal Nonane ($n\text{-}C_9H_{20}$)

Figure 3-9

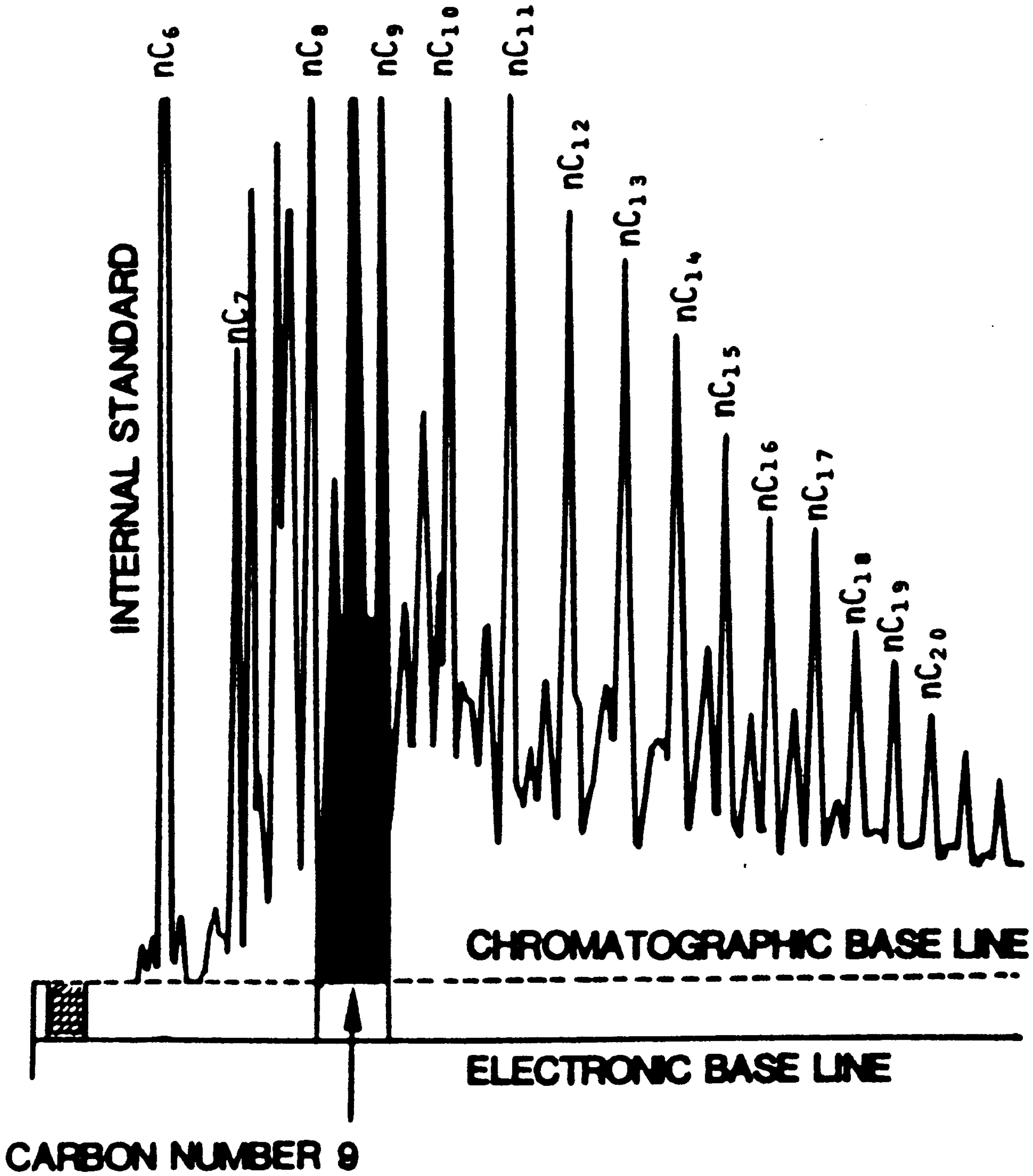

INTERNAL STANDARD
$nC_6$
$nC_7$
$nC_8$
$nC_9$
$nC_{10}$
$nC_{11}$
$nC_{12}$
$nC_{13}$
$nC_{14}$
$nC_{15}$
$nC_{16}$
$nC_{17}$
$nC_{18}$
$nC_{19}$
$nC_{20}$
CHROMATOGRAPHIC BASE LINE
ELECTRONIC BASE LINE
CARBON NUMBER 9

**Figure 3-10**

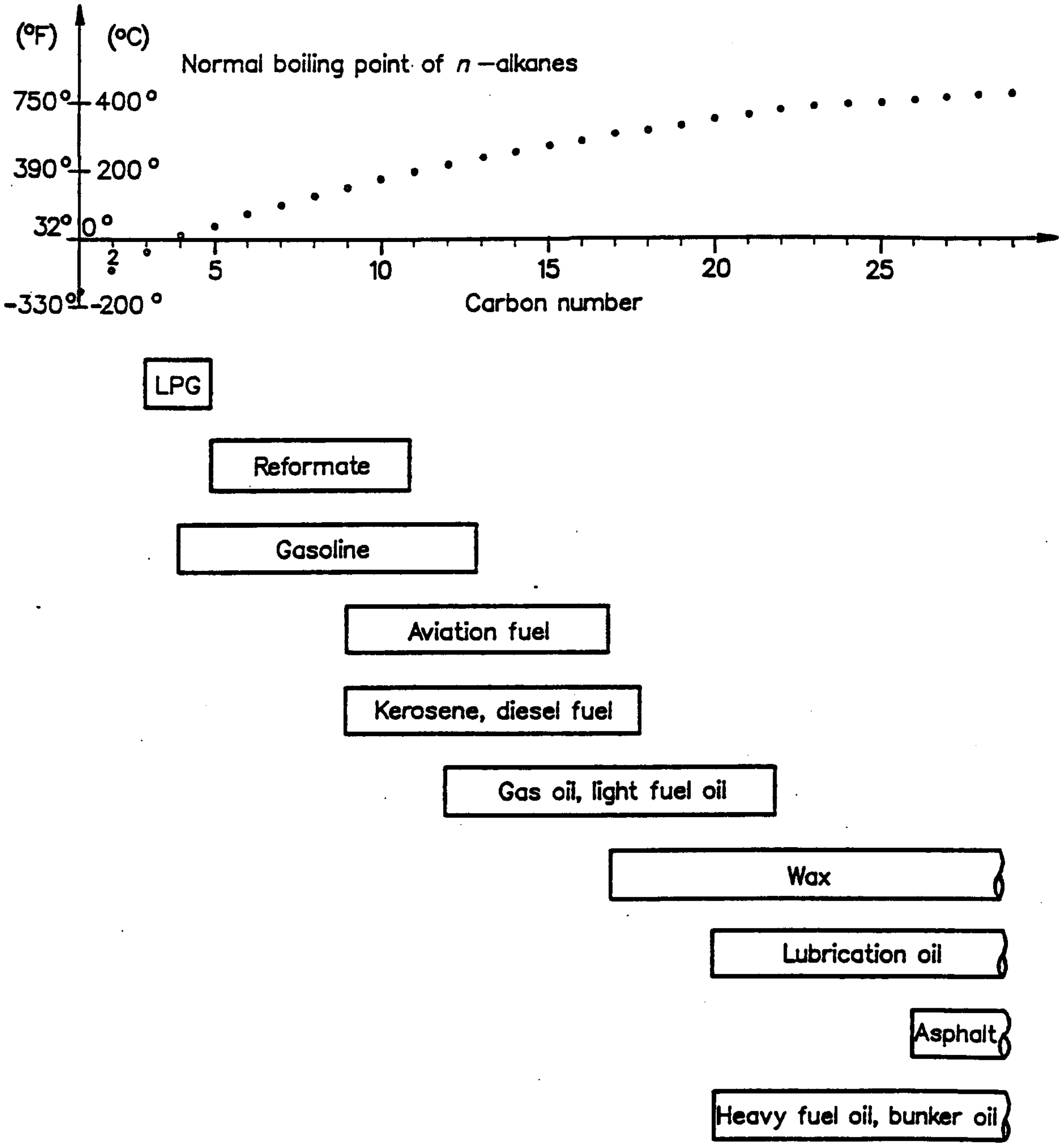

(°F)
(°C)
Normal boiling point of *n*—alkanes
750°
400°
390°
200°
32°
0°
-330°
-200°
2
5
10
15
20
25
Carbon number
LPG
Reformate
Gasoline
Aviation fuel
Kerosene, diesel fuel
Gas oil, light fuel oil
Wax
Lubrication oil
Asphalt
Heavy fuel oil, bunker oil

**Figure 3-11**

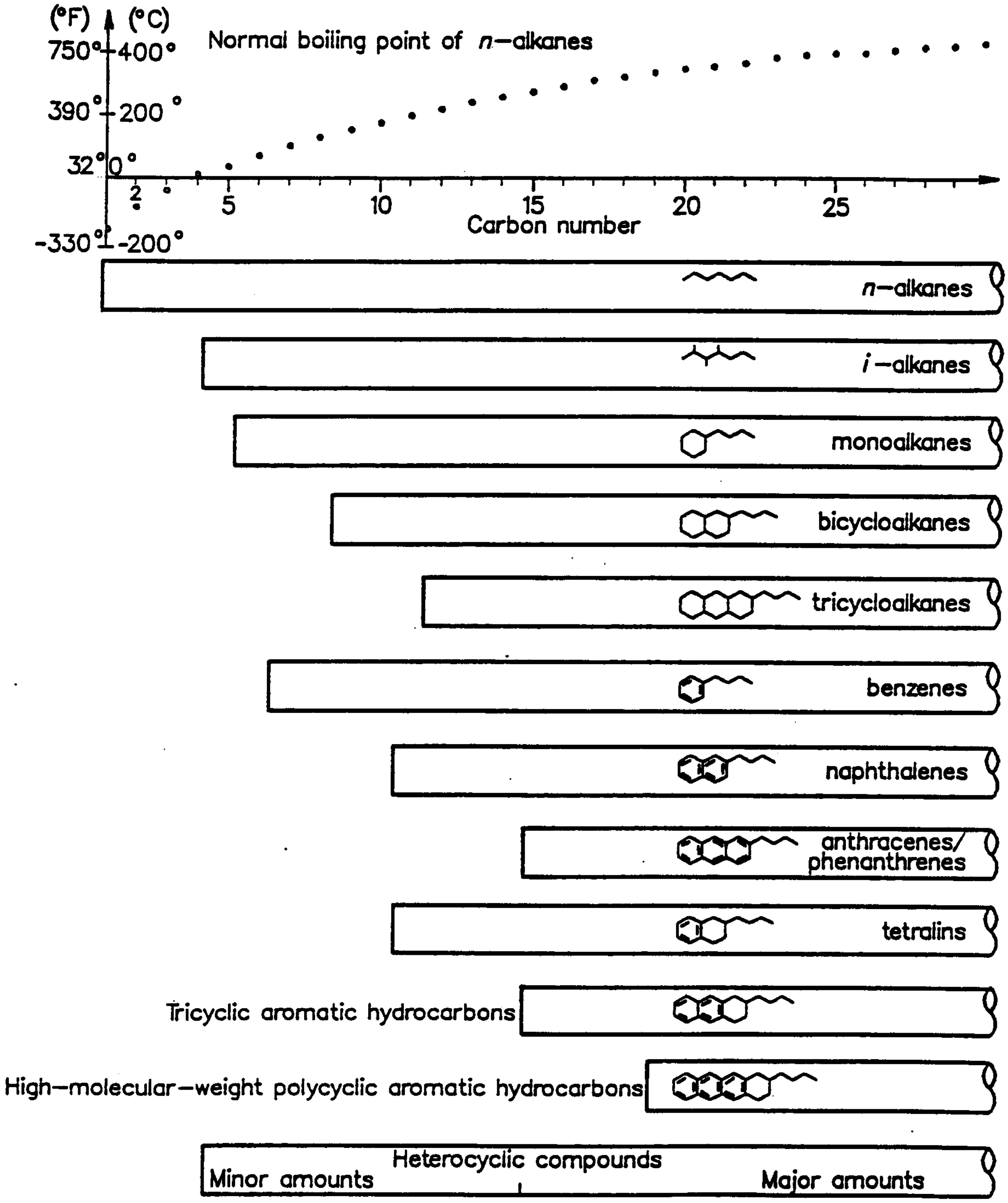

(°F)
(°C)
750°
400°
390°
200°
32°
0°
-330°
-200°
Normal boiling point of n–alkanes
2
5
10
15
20
25
Carbon number
n–alkanes
i–alkanes
monoalkanes
bicycloalkanes
tricycloalkanes
benzenes
naphthalenes
anthracenes/
phenanthrenes
tetralins
Tricyclic aromatic hydrocarbons
High–molecular–weight polycyclic aromatic hydrocarbons
Heterocyclic compounds
Minor amounts
Major amounts

**Figure 3-12**

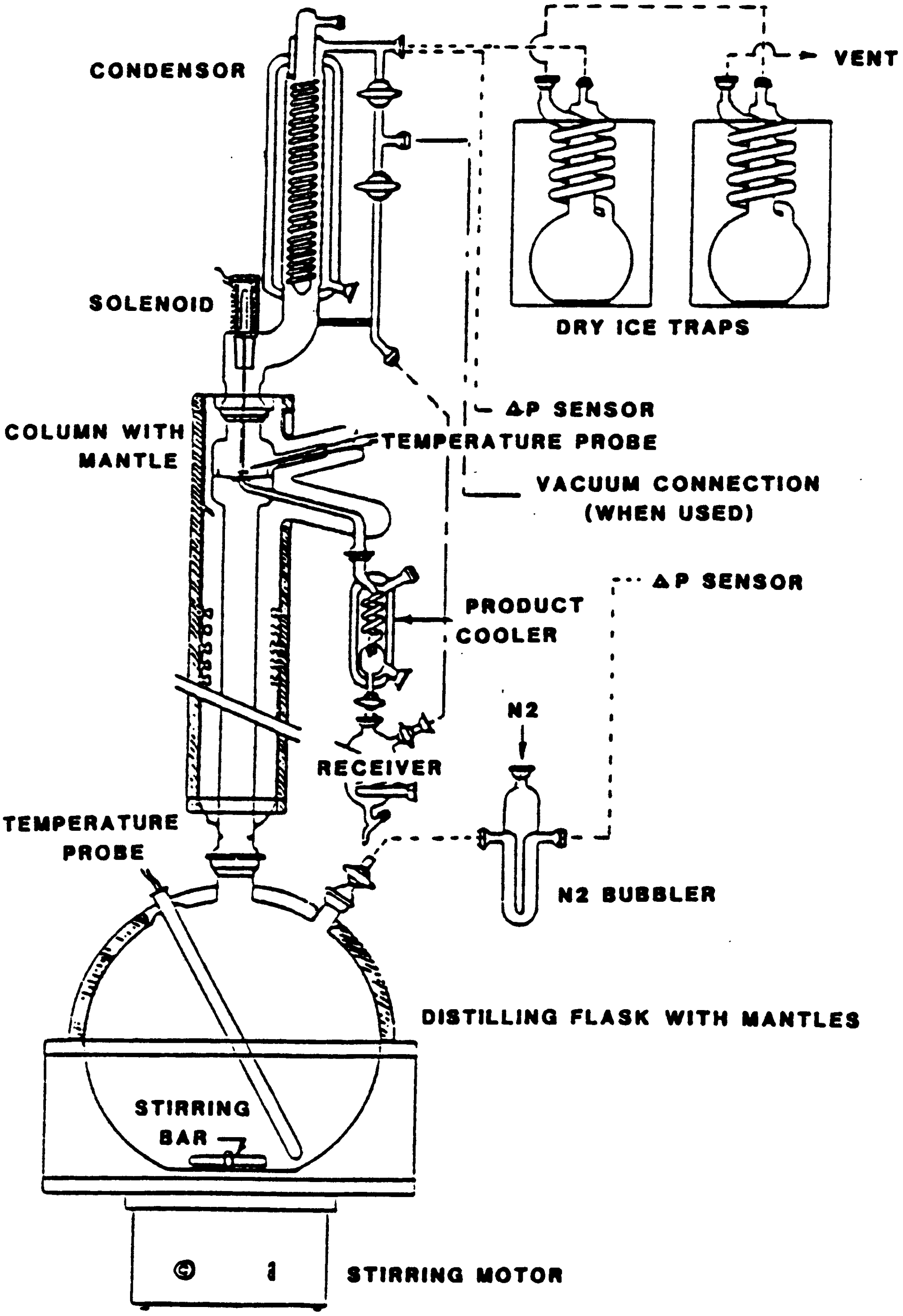
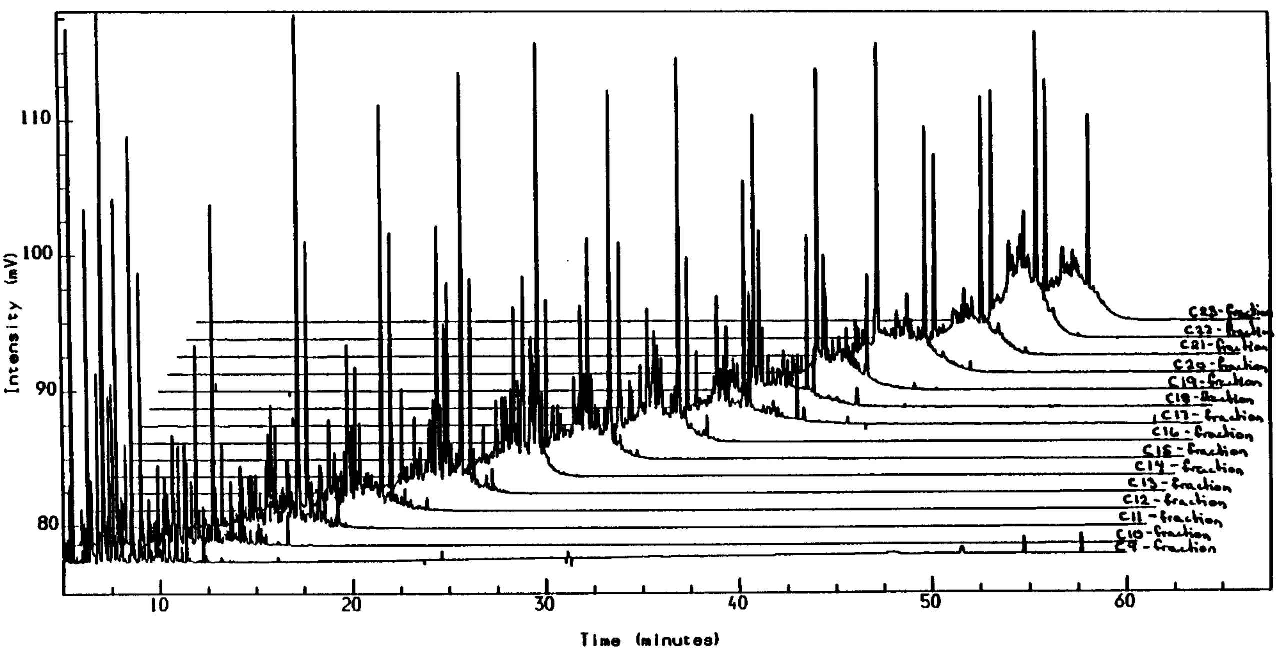

CONDENSOR
VENT
DRY ICE TRAPS
SOLENOID
ΔP SENSOR
COLUMN WITH MANTLE
TEMPERATURE PROBE
VACUUM CONNECTION (WHEN USED)
ΔP SENSOR
PRODUCT COOLER
N2
RECEIVER
TEMPERATURE PROBE
N2 BUBBLER
DISTILLING FLASK WITH MANTLES
STIRRING BAR
STIRRING MOTOR

**Figure 3-13**

Analysis Name : [PVT] 3 DEST300618.15.1.
Isometric plot by sample from 1.1 to 16.1.
DESTKUTT C9 -C23



Instrument : HP5880
Channel Title : HP5880 GC
Lims ID :
Acquired on 2-OCT-1990 at 10:42
Reported on 3-OCT-1990 at 18:53

Method : DESTCUT1
Calibration :
Run Sequence : WAX

Figure 3-14

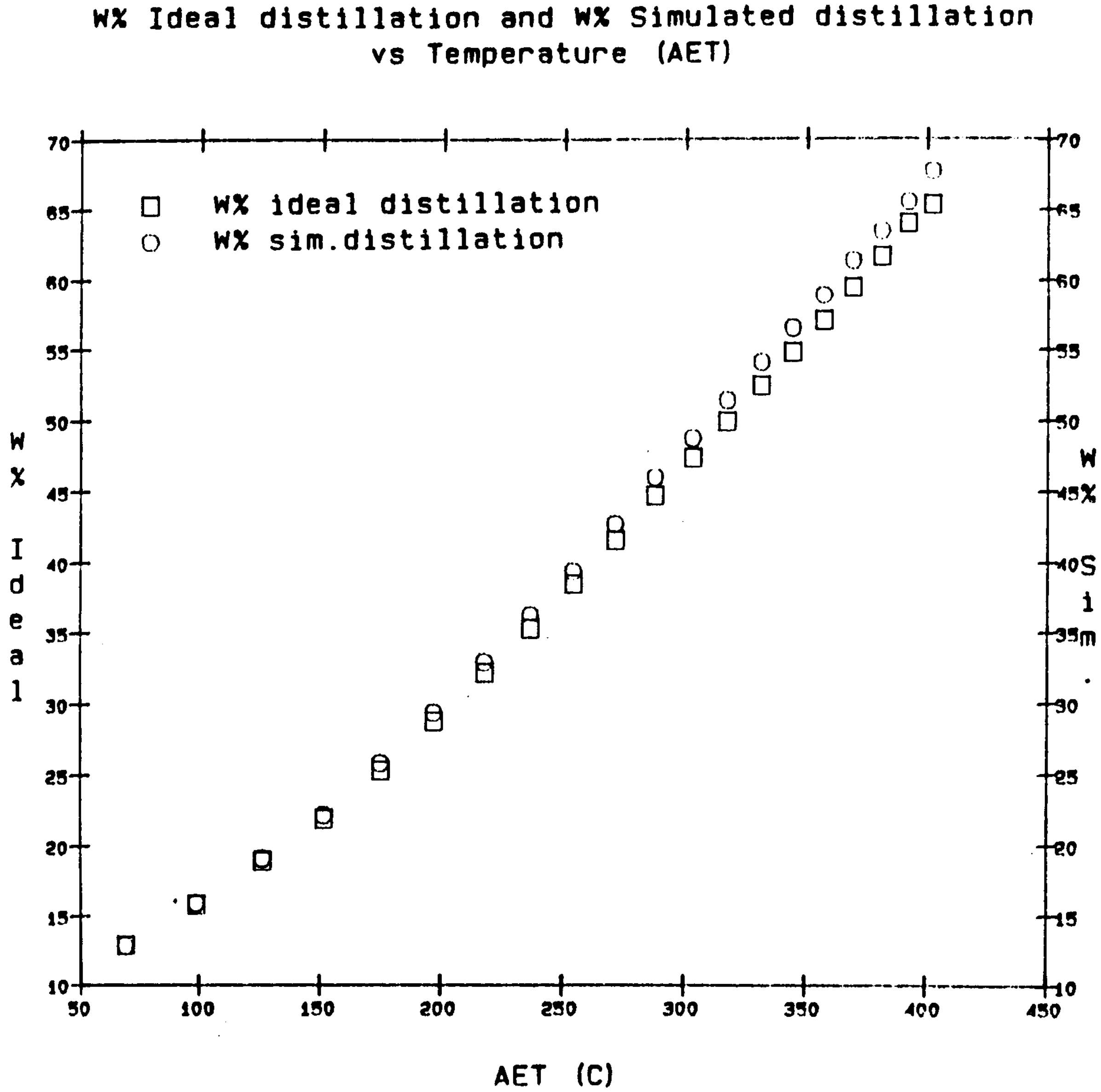

W% Ideal distillation and W% Simulated distillation
vs Temperature (AET)
□ W% ideal distillation
○ W% sim.distillation
W% Ideal
W% Sim.
AET (C)
10
15
20
25
30
35
40
45
50
55
60
65
70
50
100
150
200
250
300
350
400
450

Figure 3-15

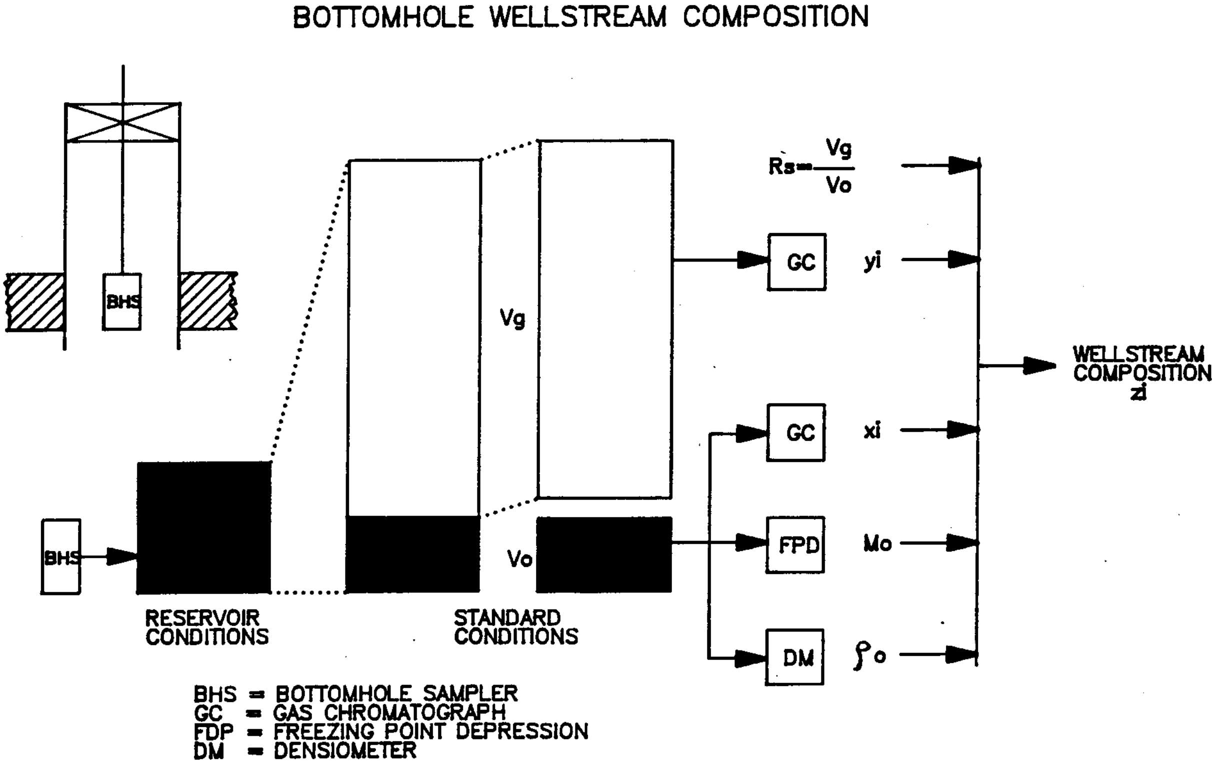

BOTTOMHOLE WELLSTREAM COMPOSITION
BHS
BHS
RESERVOIR CONDITIONS
Vg
Vo
STANDARD CONDITIONS
Rs = Vg/Vo
GC
yi
GC
xi
FPD
Mo
DM
ρo
WELLSTREAM COMPOSITION zi
BHS = BOTTOMHOLE SAMPLER
GC = GAS CHROMATOGRAPH
FDP = FREEZING POINT DEPRESSION
DM = DENSIOMETER

Figure 3-16

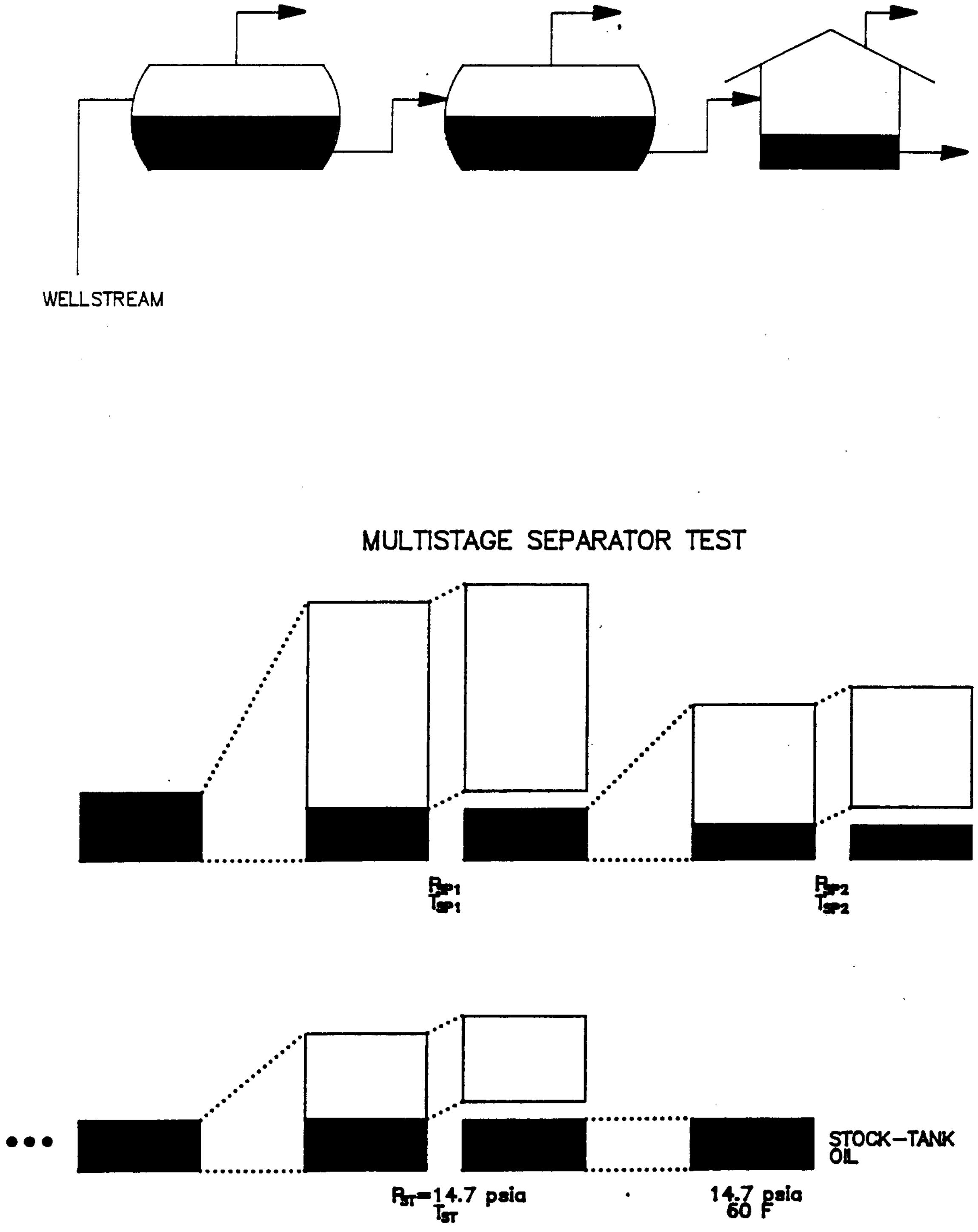

WELLSTREAM
MULTISTAGE SEPARATOR TEST
P_SP1
T_SP1
P_SP2
T_SP2
P_ST=14.7 psia
T_ST
14.7 psia
60 F
STOCK-TANK OIL

**Figure 3-17**

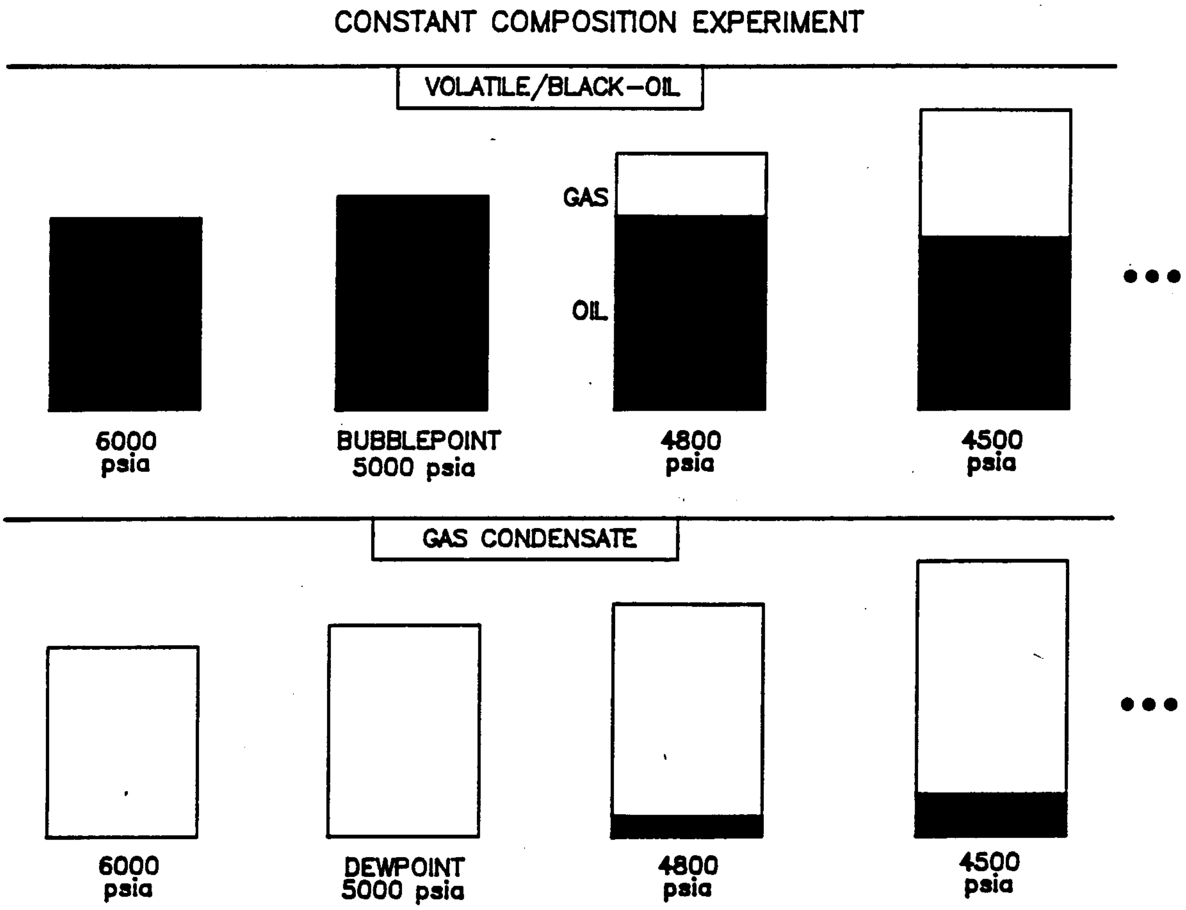

CONSTANT COMPOSITION EXPERIMENT
VOLATILE/BLACK-OIL
GAS
OIL
6000 psia
BUBBLEPOINT 5000 psia
4800 psia
4500 psia
GAS CONDENSATE
6000 psia
DEWPOINT 5000 psia
4800 psia
4500 psia

Figure 3-18

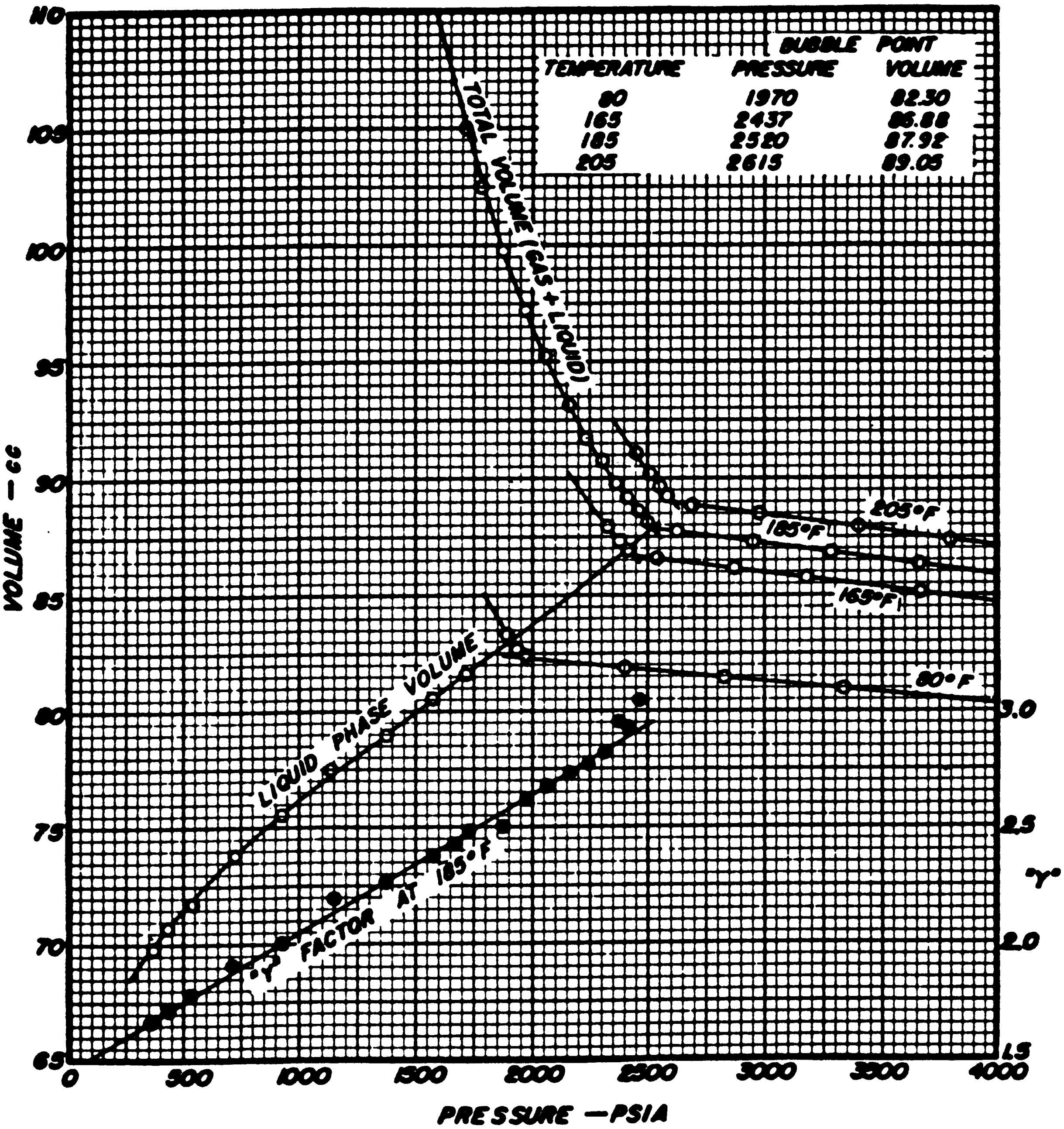

BUBBLE POINT
TEMPERATURE PRESSURE VOLUME
80 1970 82.30
165 2437 86.88
185 2520 87.92
205 2615 89.05
TOTAL VOLUME (GAS + LIQUID)
LIQUID PHASE VOLUME
"Y" FACTOR AT 185°F
205°F
185°F
165°F
80°F
VOLUME — cc
110
105
100
95
90
85
80
75
70
65
"Y"
3.0
2.5
2.0
1.5
0
500
1000
1500
2000
2500
3000
3500
4000
PRESSURE —PSIA

Figure 3-19

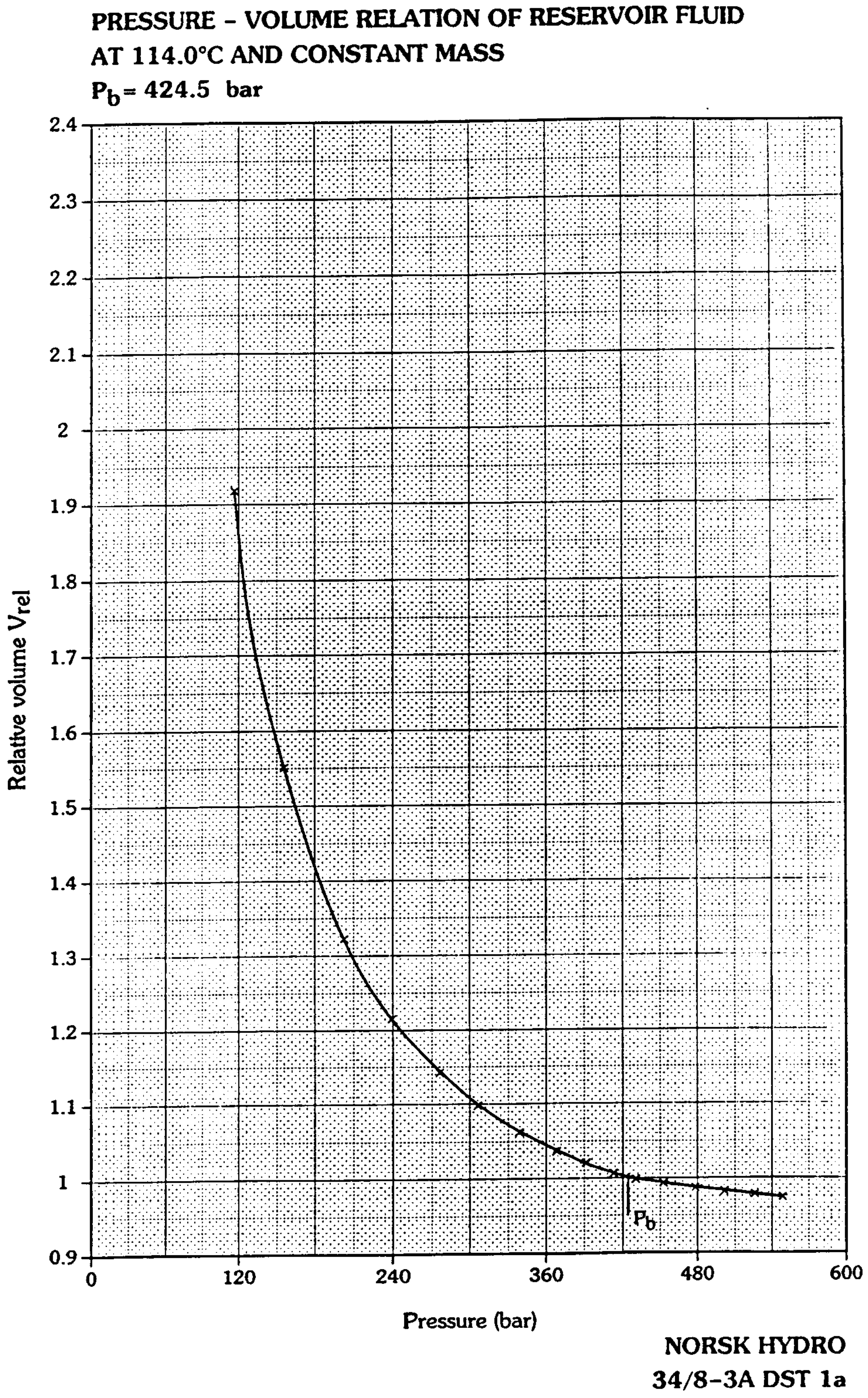

PRESSURE - VOLUME RELATION OF RESERVOIR FLUID
AT 114.0°C AND CONSTANT MASS
Pb = 424.5 bar
Relative volume Vrel
2.4
2.3
2.2
2.1
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0
120
240
360
480
600
Pressure (bar)
Pb
NORSK HYDRO
34/8-3A DST 1a

Figure 3-20

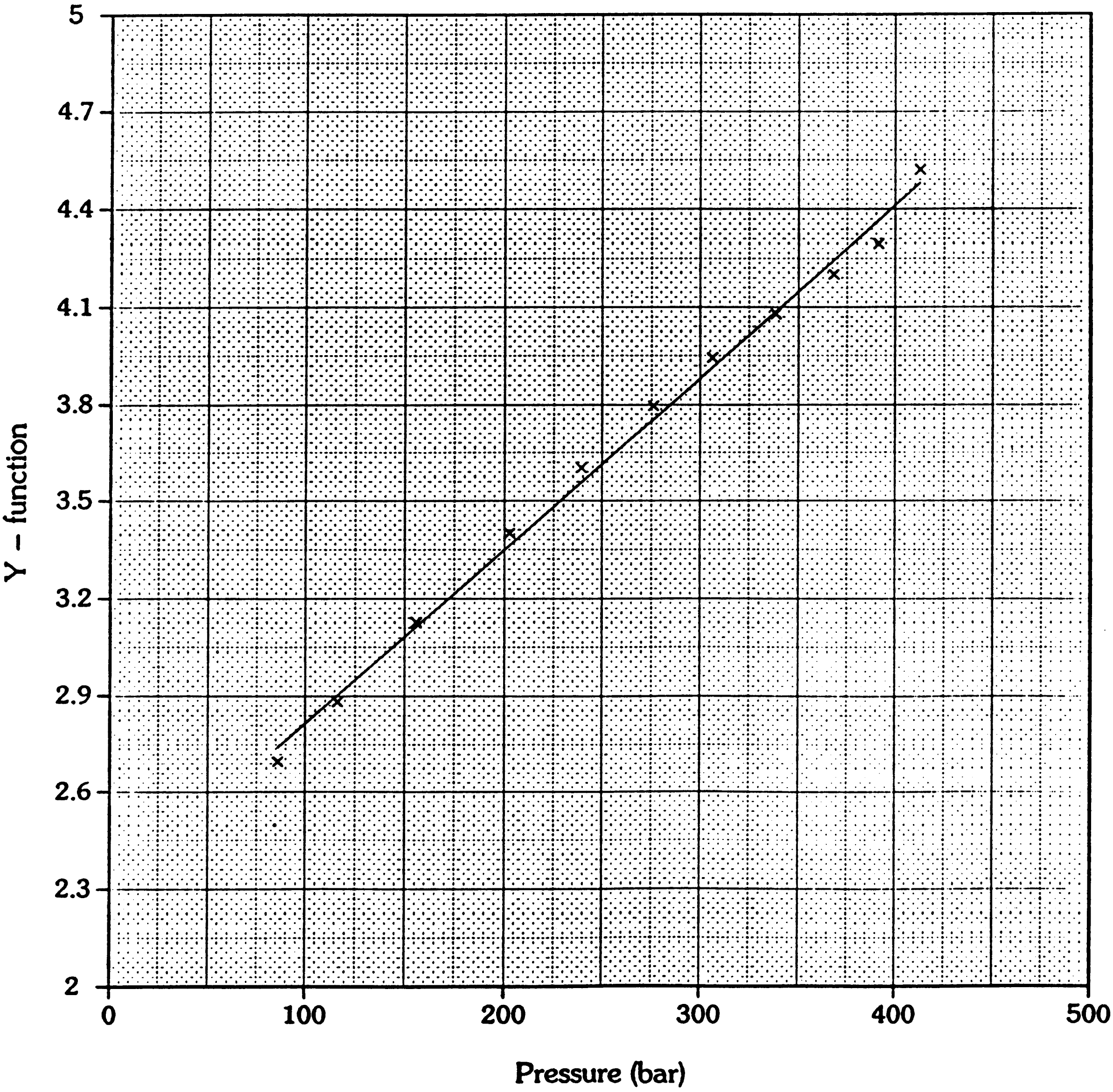
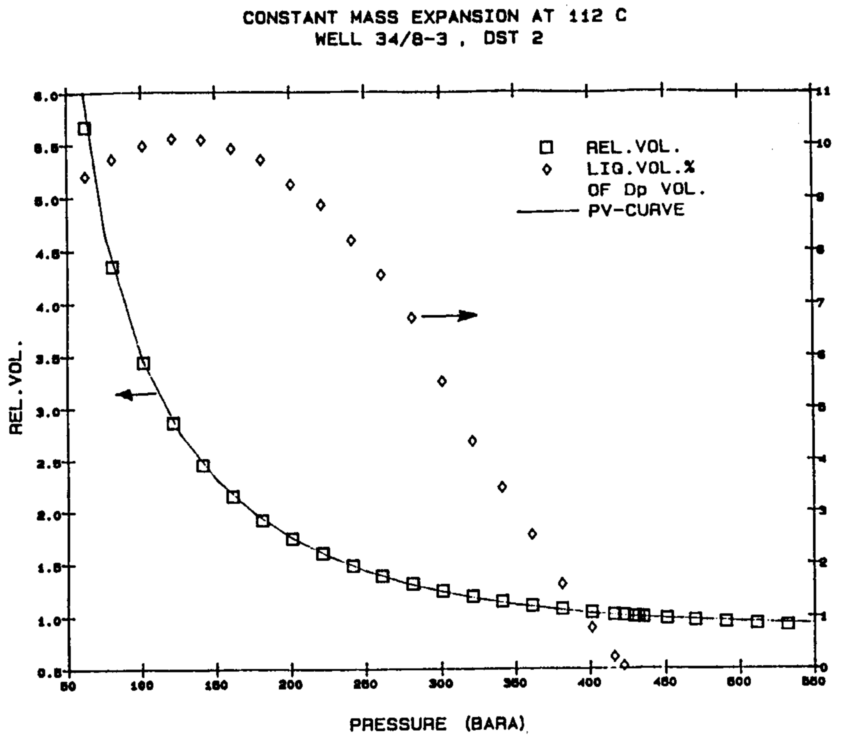

5
4.7
4.4
4.1
3.8
3.5
3.2
2.9
2.6
2.3
2
Y – function
0
100
200
300
400
500
Pressure (bar)

**Figure 3-21**



DEWPOINT : 430 BAR

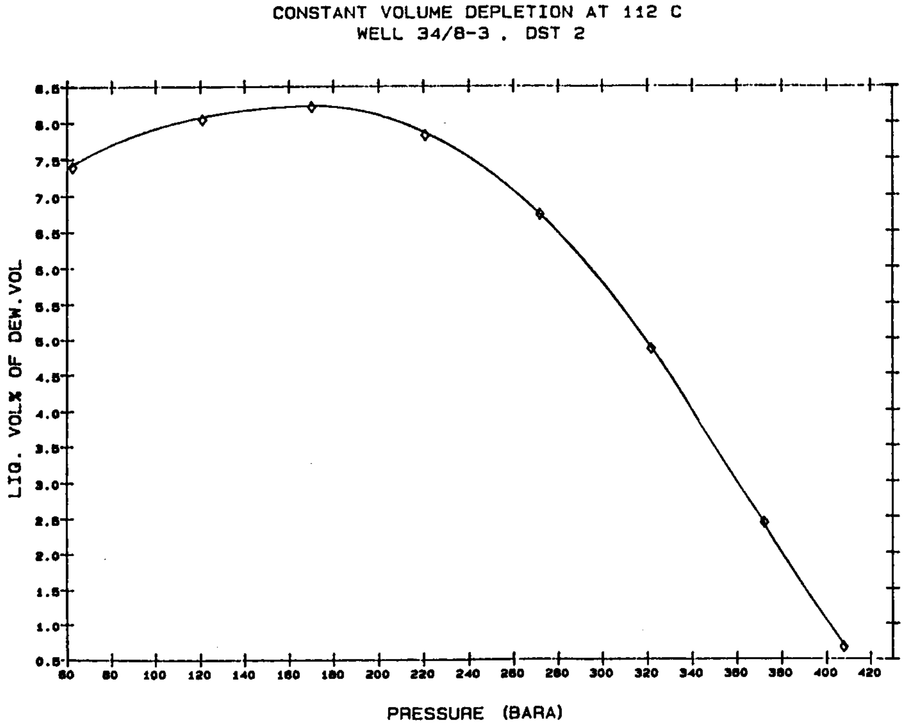


Figure 3-22

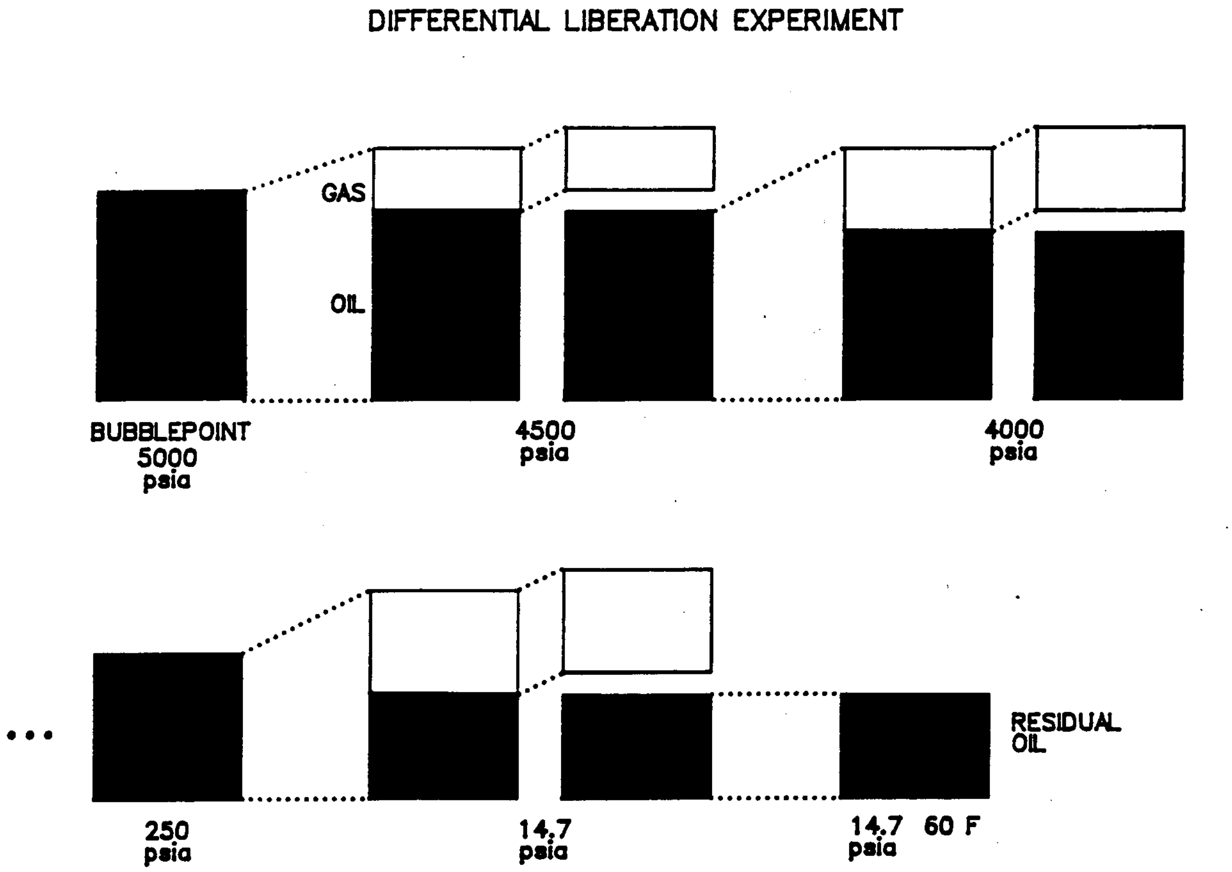

DIFFERENTIAL LIBERATION EXPERIMENT
GAS
OIL
BUBBLEPOINT 5000 psia
4500 psia
4000 psia
• • •
250 psia
14.7 psia
14.7 psia 60 F
RESIDUAL OIL

Figure 3-23

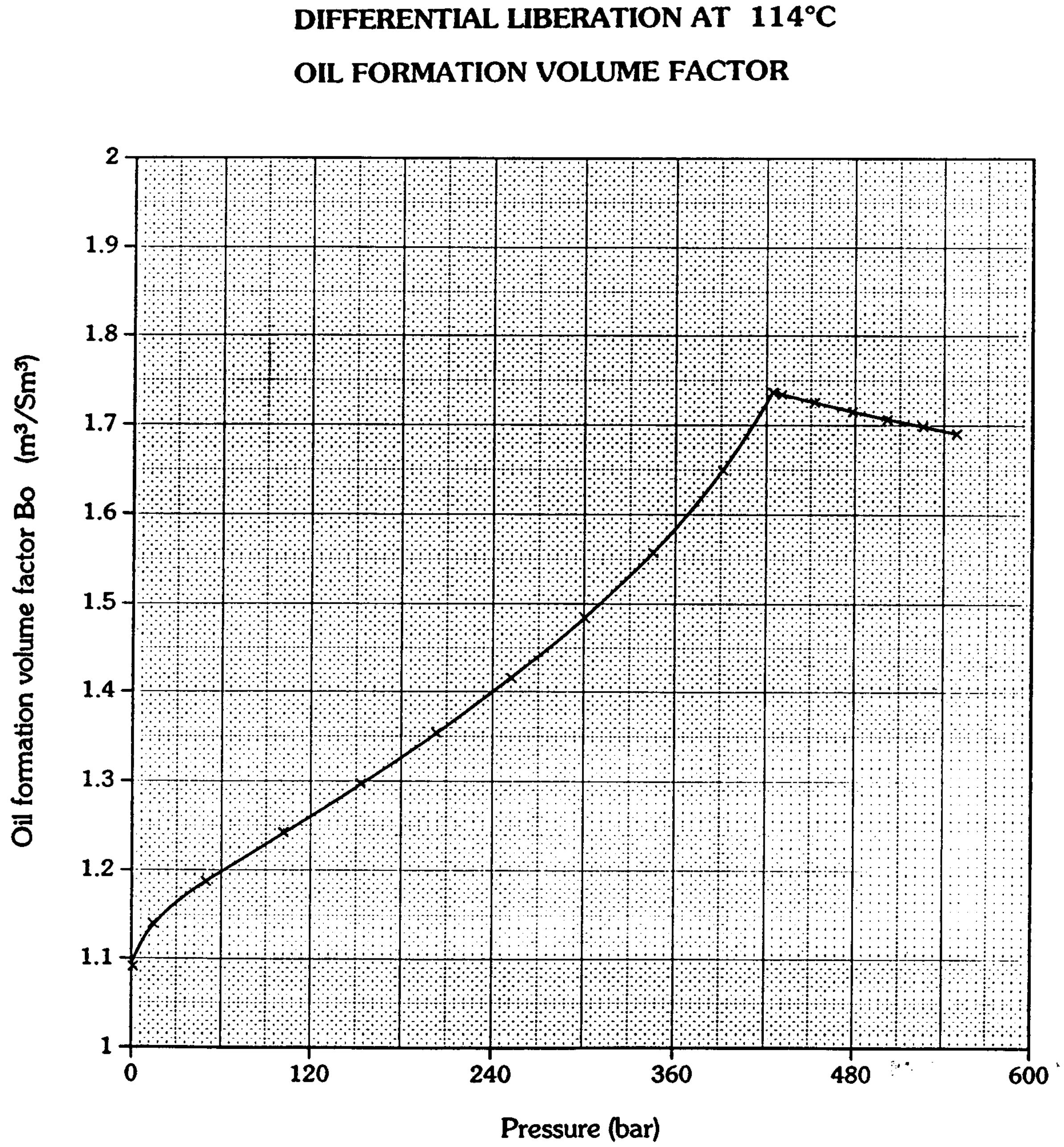

DIFFERENTIAL LIBERATION AT 114°C
OIL FORMATION VOLUME FACTOR
Oil formation volume factor Bo (m³/Sm³)
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0
120
240
360
480
600
Pressure (bar)

Figure 3-24

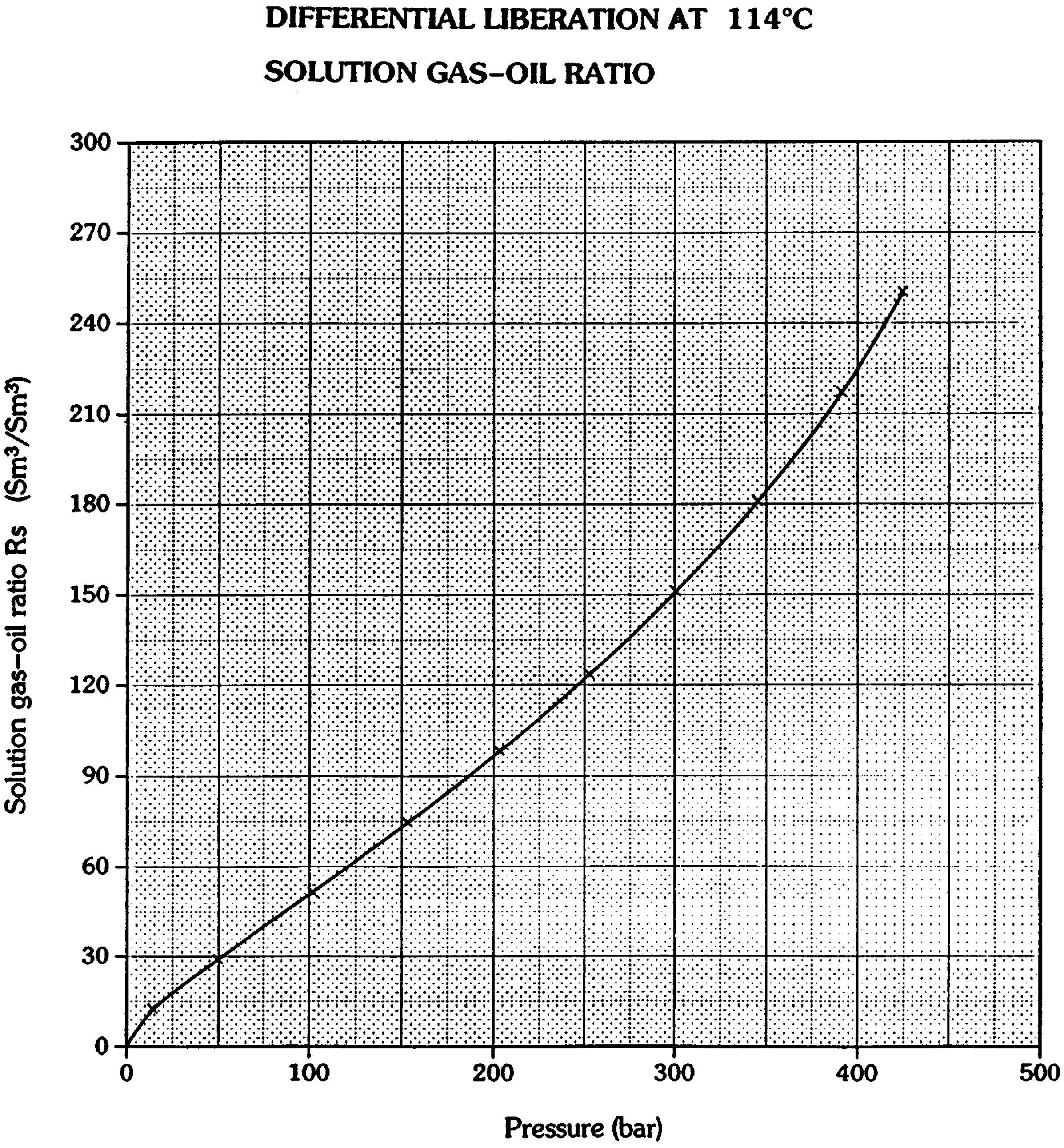
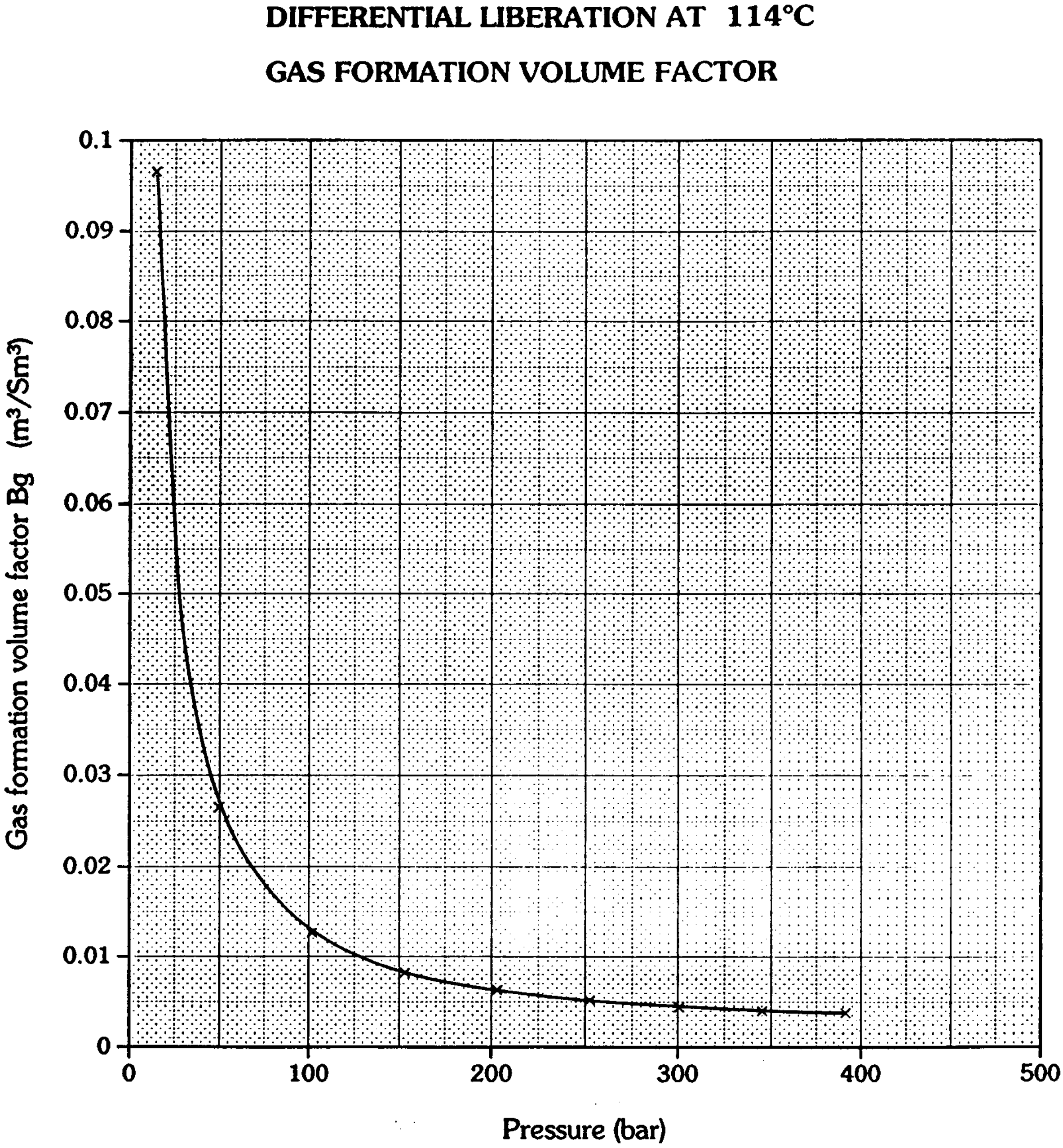

DIFFERENTIAL LIBERATION AT 114°C
SOLUTION GAS-OIL RATIO
Solution gas-oil ratio Rs (Sm³/Sm³)
300
270
240
210
180
150
120
90
60
30
0
0
100
200
300
400
500
Pressure (bar)

**Figure 3-25**

---


DIFFERENTIAL LIBERATION AT 114°C
GAS FORMATION VOLUME FACTOR
Gas formation volume factor Bg (m³/Sm³)
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0
100
200
300
400
500
Pressure (bar)

---

Figure 3-26

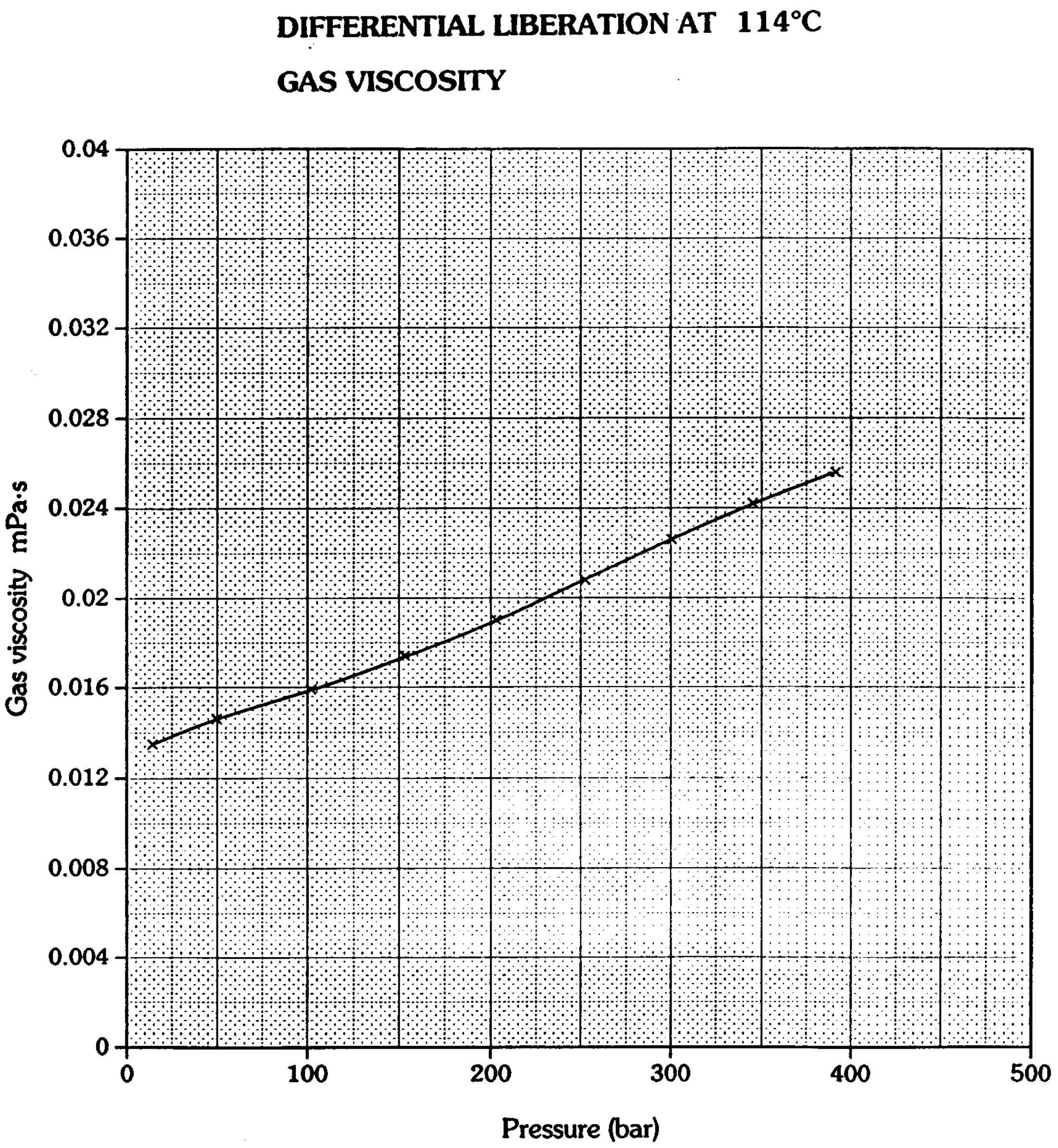

DIFFERENTIAL LIBERATION AT 114°C
GAS VISCOSITY
Gas viscosity mPa·s
0.04
0.036
0.032
0.028
0.024
0.02
0.016
0.012
0.008
0.004
0
0
100
200
300
400
500
Pressure (bar)

Figure 3-27

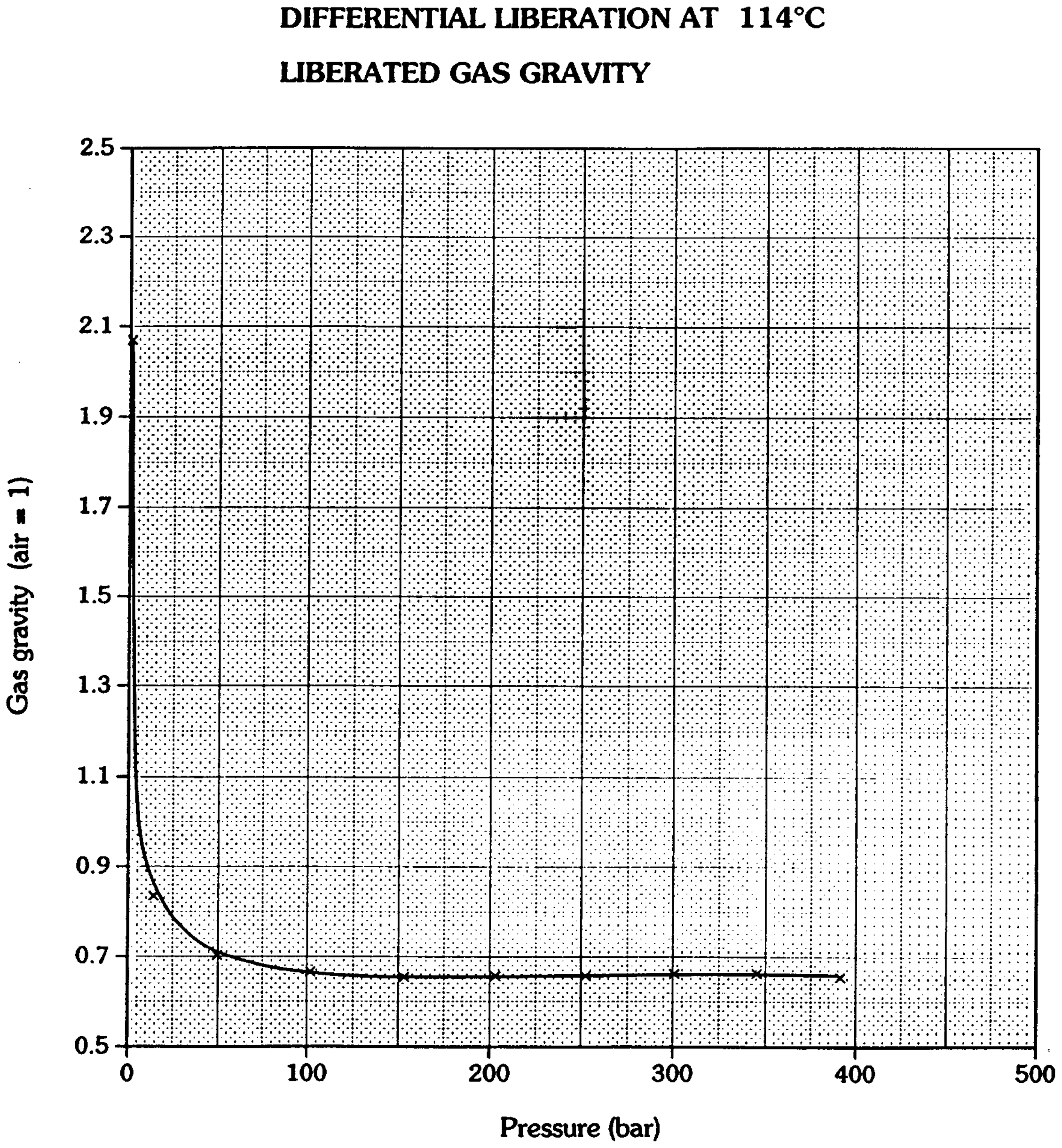

DIFFERENTIAL LIBERATION AT 114°C
LIBERATED GAS GRAVITY
Gas gravity (air = 1)
2.5
2.3
2.1
1.9
1.7
1.5
1.3
1.1
0.9
0.7
0.5
0
100
200
300
400
500
Pressure (bar)

Figure 3-28

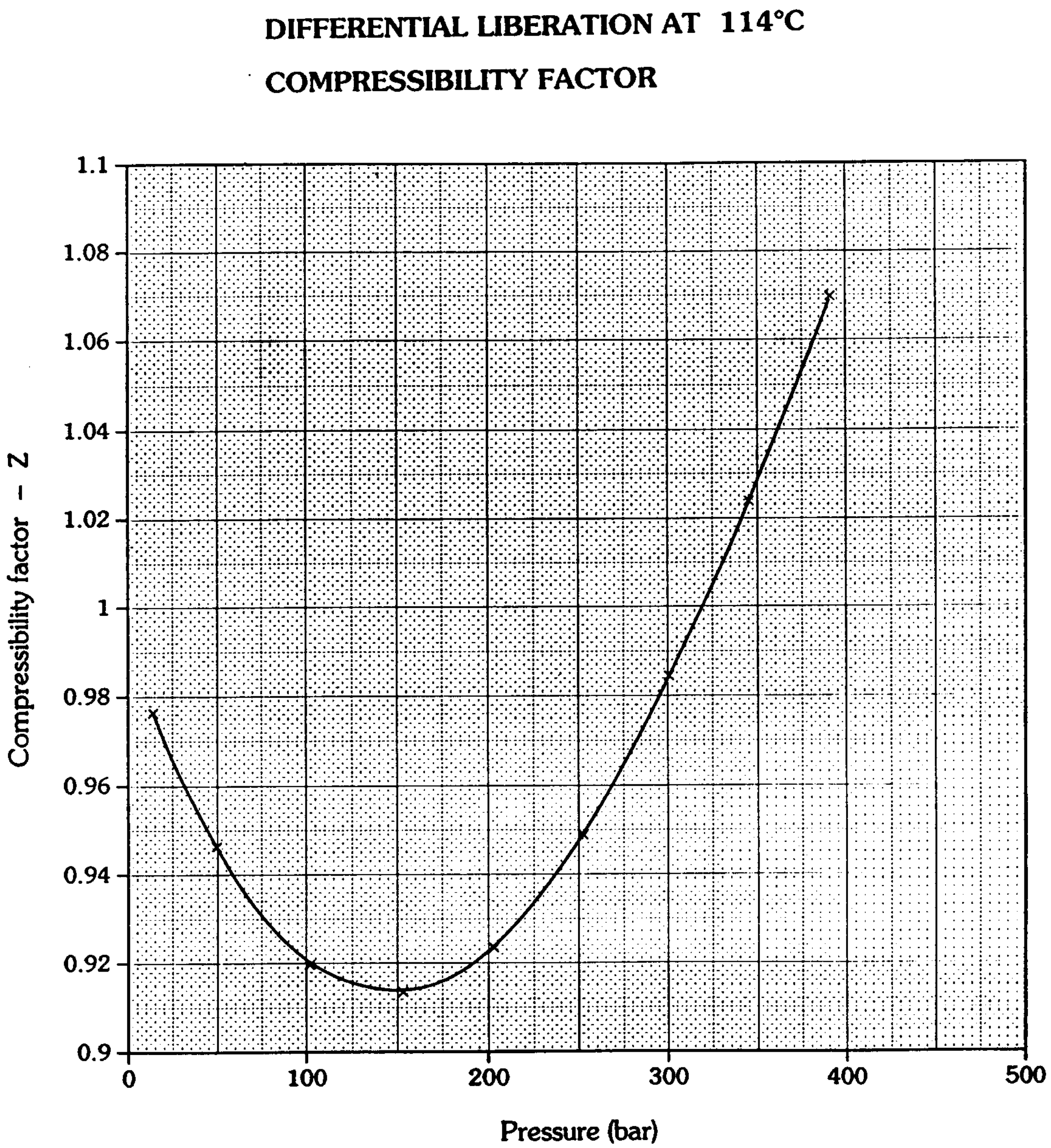

DIFFERENTIAL LIBERATION AT 114°C
COMPRESSIBILITY FACTOR
Compressibility factor – Z
1.1
1.08
1.06
1.04
1.02
1
0.98
0.96
0.94
0.92
0.9
0
100
200
300
400
500
Pressure (bar)

**Figure 3-27**

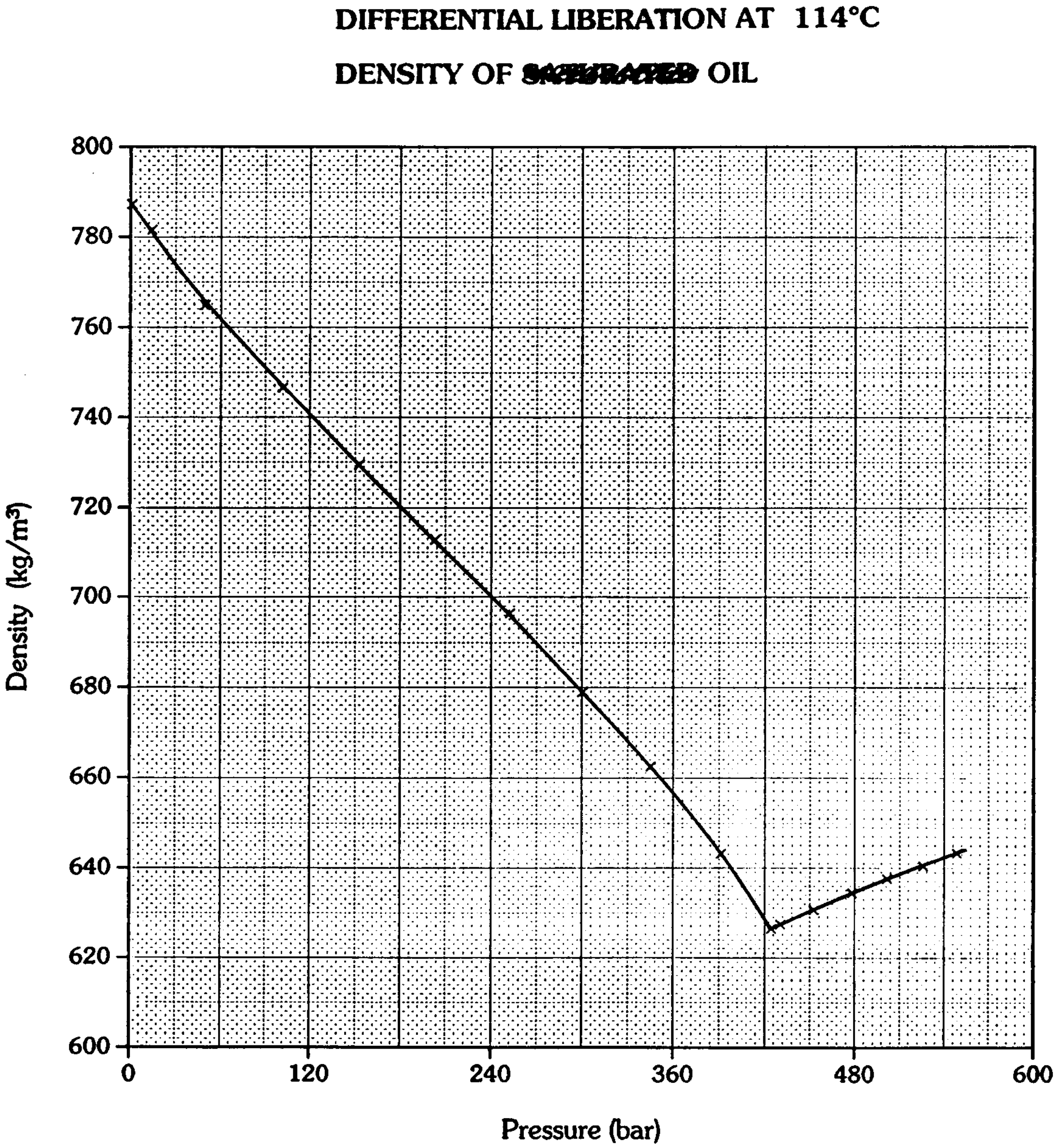

DIFFERENTIAL LIBERATION AT 114°C
DENSITY OF [redacted] OIL
800
780
760
740
720
700
680
660
640
620
600
Density (kg/m³)
0
120
240
360
480
600
Pressure (bar)

Figure 3-30

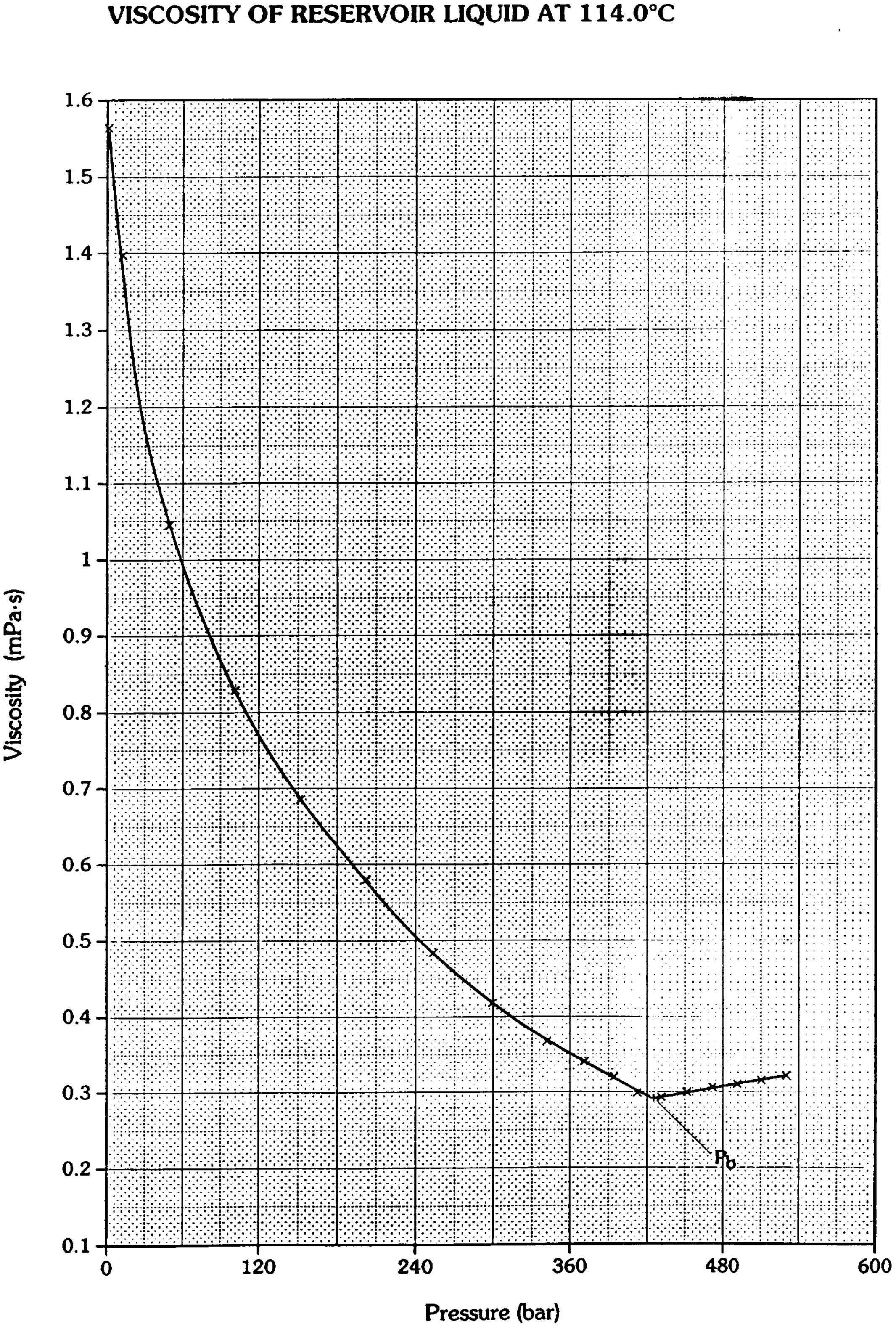

VISCOSITY OF RESERVOIR LIQUID AT 114.0°C
Viscosity (mPa·s)
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
120
240
360
480
600
Pressure (bar)
$P_b$

**Figure 3-31**

RELATIVE OIL VOLUME

TO STOCK TANK CONDITION

BASIS: THREE STAGE SEPARATOR TEST

1) Oil formation volume factor from differential liberation data at given pressure.
2) Relative oil volume based on three stage flash at given pressure.

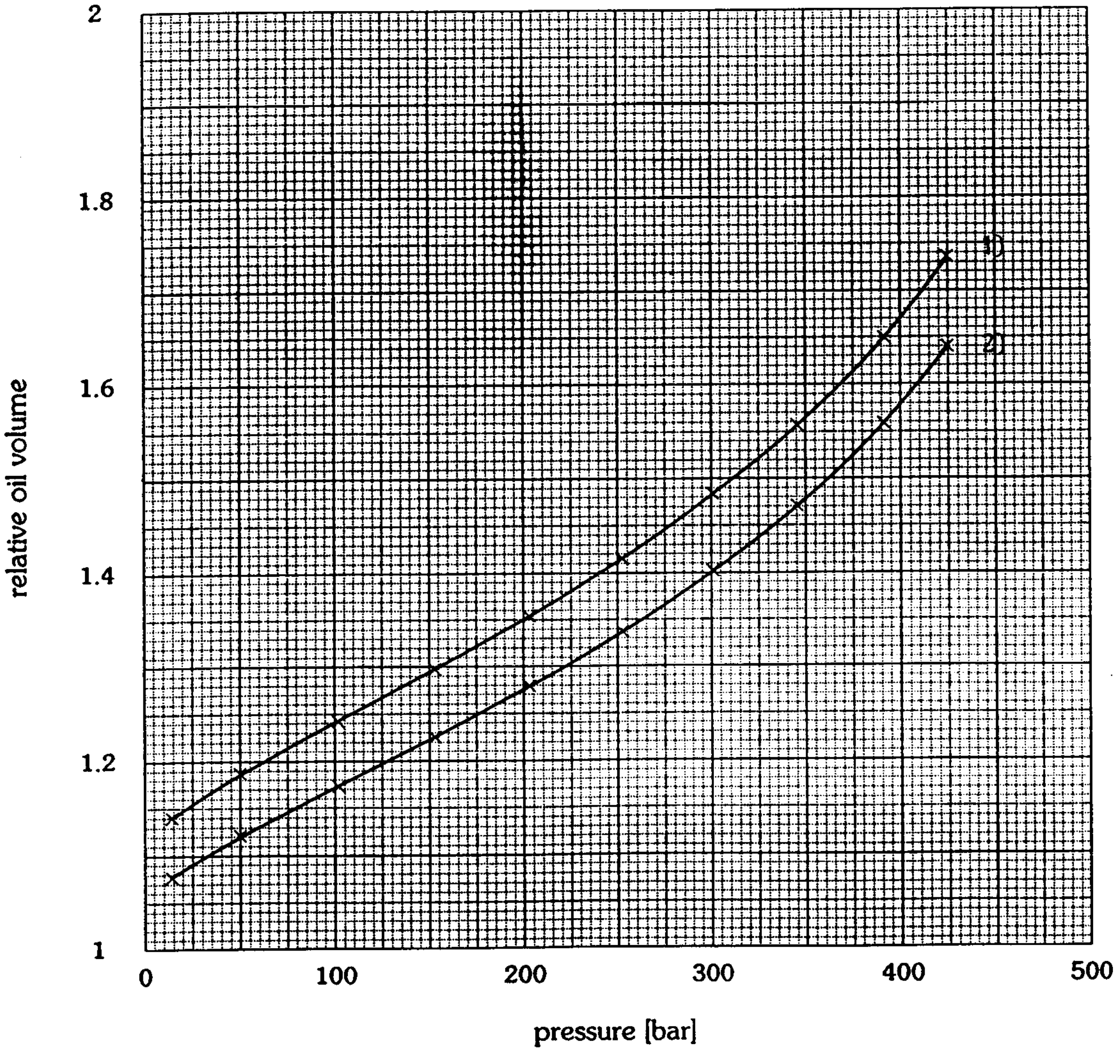


**Figure 3-32**

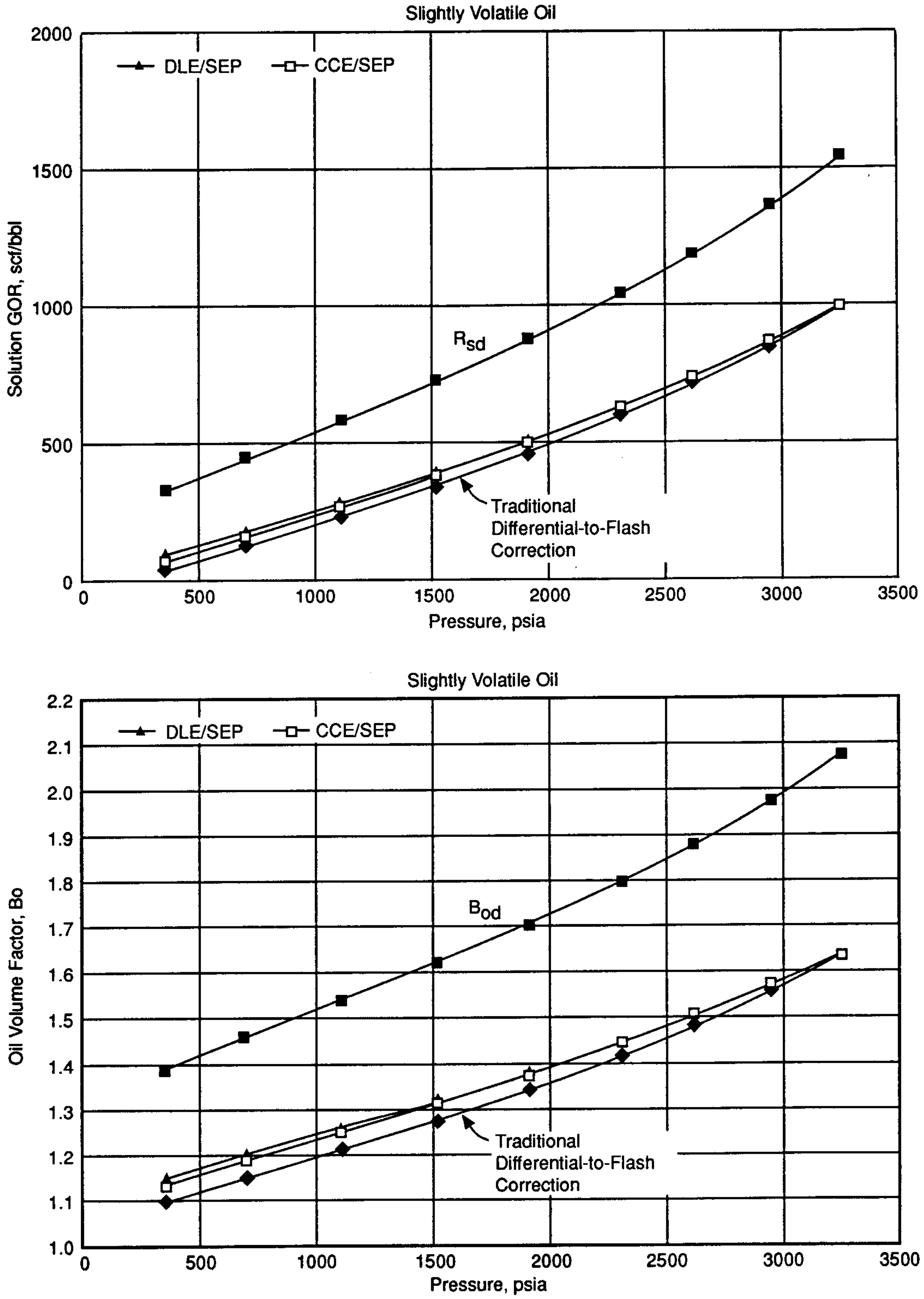

Slightly Volatile Oil
DLE/SEP
CCE/SEP
$R_{sd}$
Traditional Differential-to-Flash Correction
Solution GOR, scf/bbl
0
500
1000
1500
2000
0
500
1000
1500
2000
2500
3000
3500
Pressure, psia
Slightly Volatile Oil
DLE/SEP
CCE/SEP
$B_{od}$
Traditional Differential-to-Flash Correction
Oil Volume Factor, Bo
1.0
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
2.1
2.2
0
500
1000
1500
2000
2500
3000
3500
Pressure, psia

**Figure 3-33**

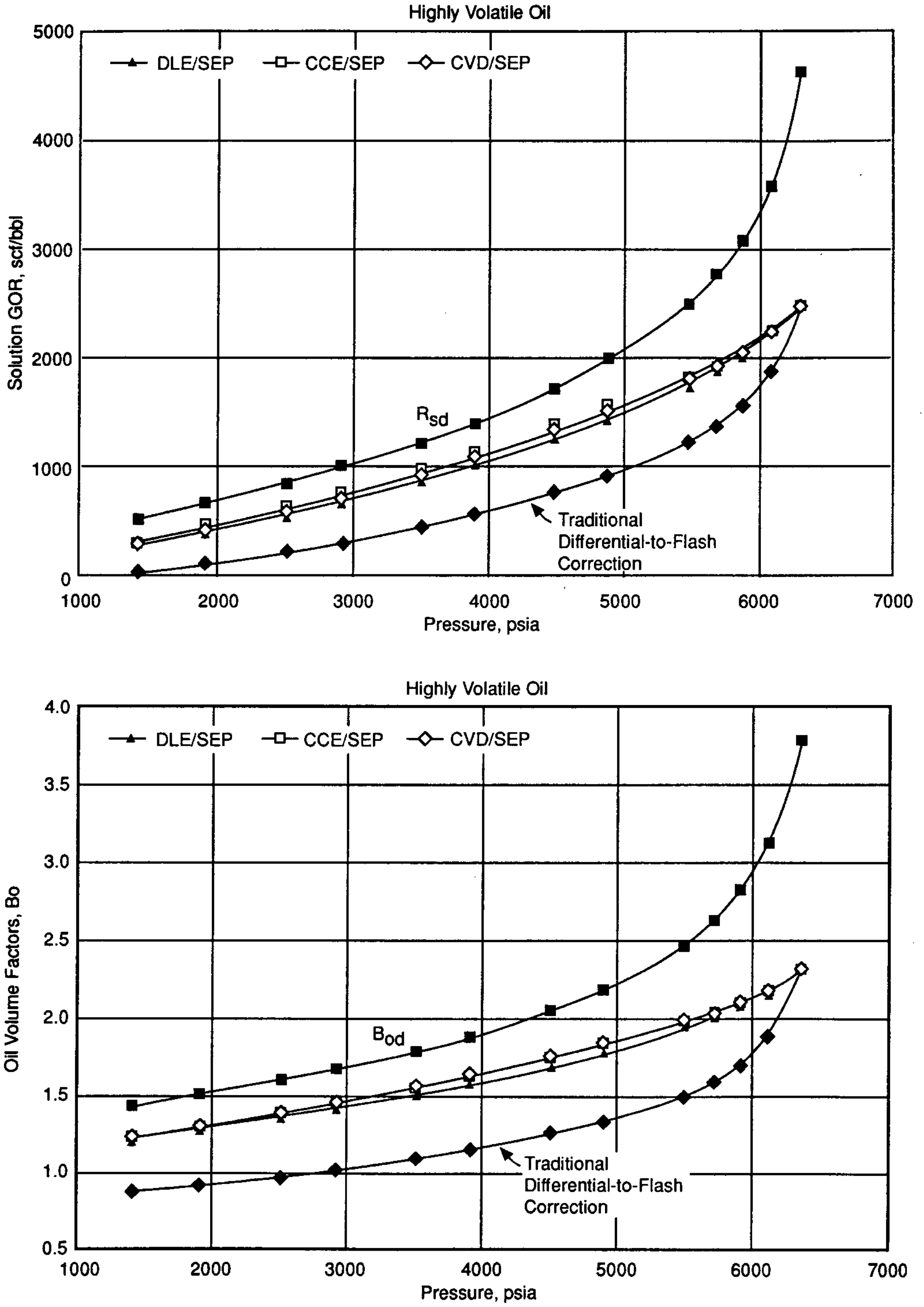

Highly Volatile Oil
DLE/SEP
CCE/SEP
CVD/SEP
Solution GOR, scf/bbl
5000
4000
3000
2000
1000
0
$R_{sd}$
Traditional Differential-to-Flash Correction
1000
2000
3000
4000
5000
6000
7000
Pressure, psia
Highly Volatile Oil
DLE/SEP
CCE/SEP
CVD/SEP
Oil Volume Factors, Bo
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
$B_{od}$
Traditional Differential-to-Flash Correction
1000
2000
3000
4000
5000
6000
7000
Pressure, psia

Figure 3-34

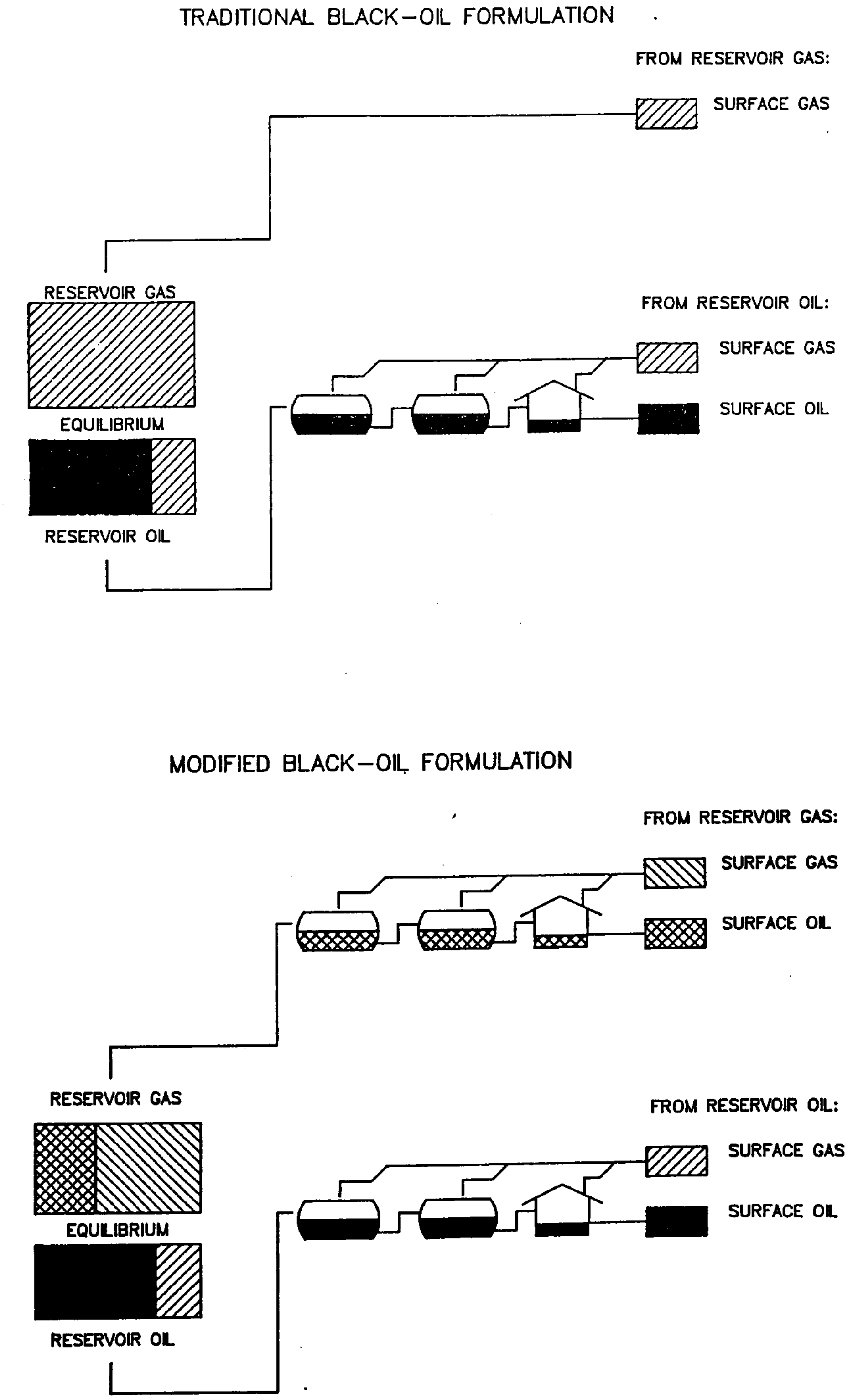

TRADITIONAL BLACK-OIL FORMULATION
FROM RESERVOIR GAS:
SURFACE GAS
RESERVOIR GAS
EQUILIBRIUM
RESERVOIR OIL
FROM RESERVOIR OIL:
SURFACE GAS
SURFACE OIL
MODIFIED BLACK-OIL FORMULATION
FROM RESERVOIR GAS:
SURFACE GAS
SURFACE OIL
RESERVOIR GAS
EQUILIBRIUM
RESERVOIR OIL
FROM RESERVOIR OIL:
SURFACE GAS
SURFACE OIL

**Figure 3-27**

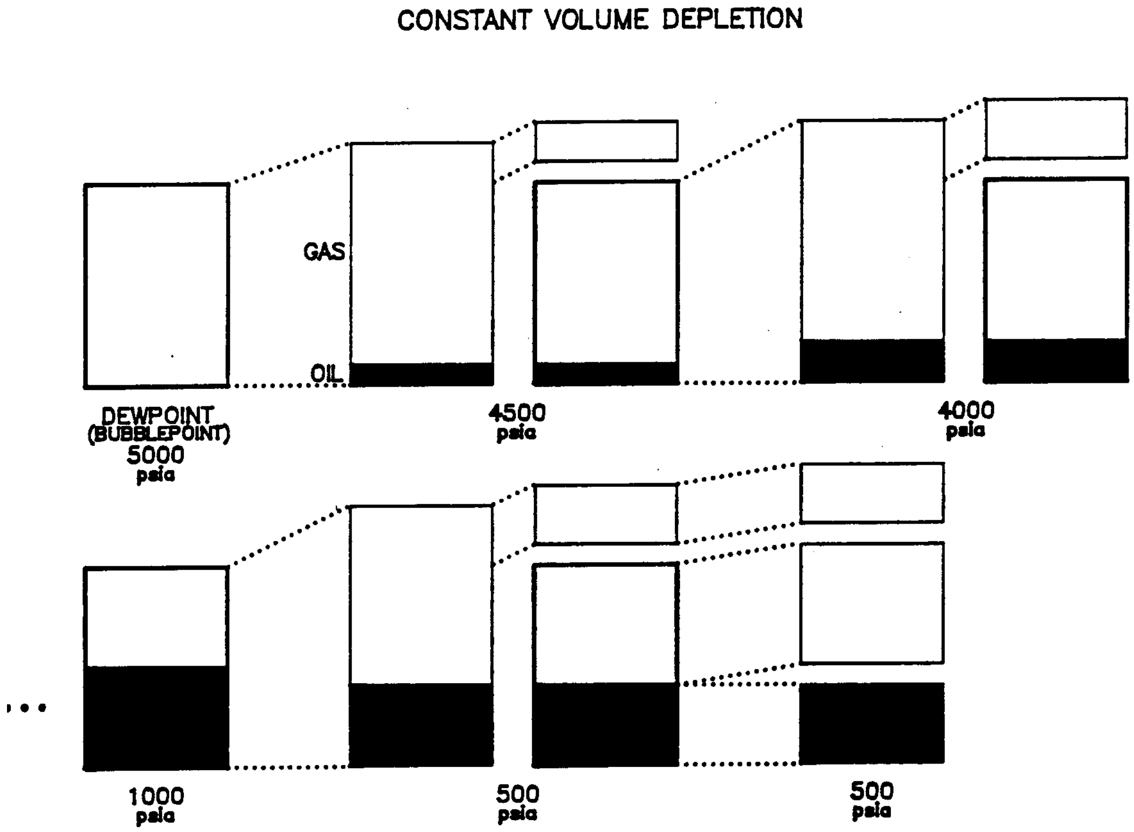

CONSTANT VOLUME DEPLETION
GAS
OIL
DEWPOINT
(BUBBLEPOINT)
5000
psia
4500
psia
4000
psia
...
1000
psia
500
psia
500
psia

Figure 3-36

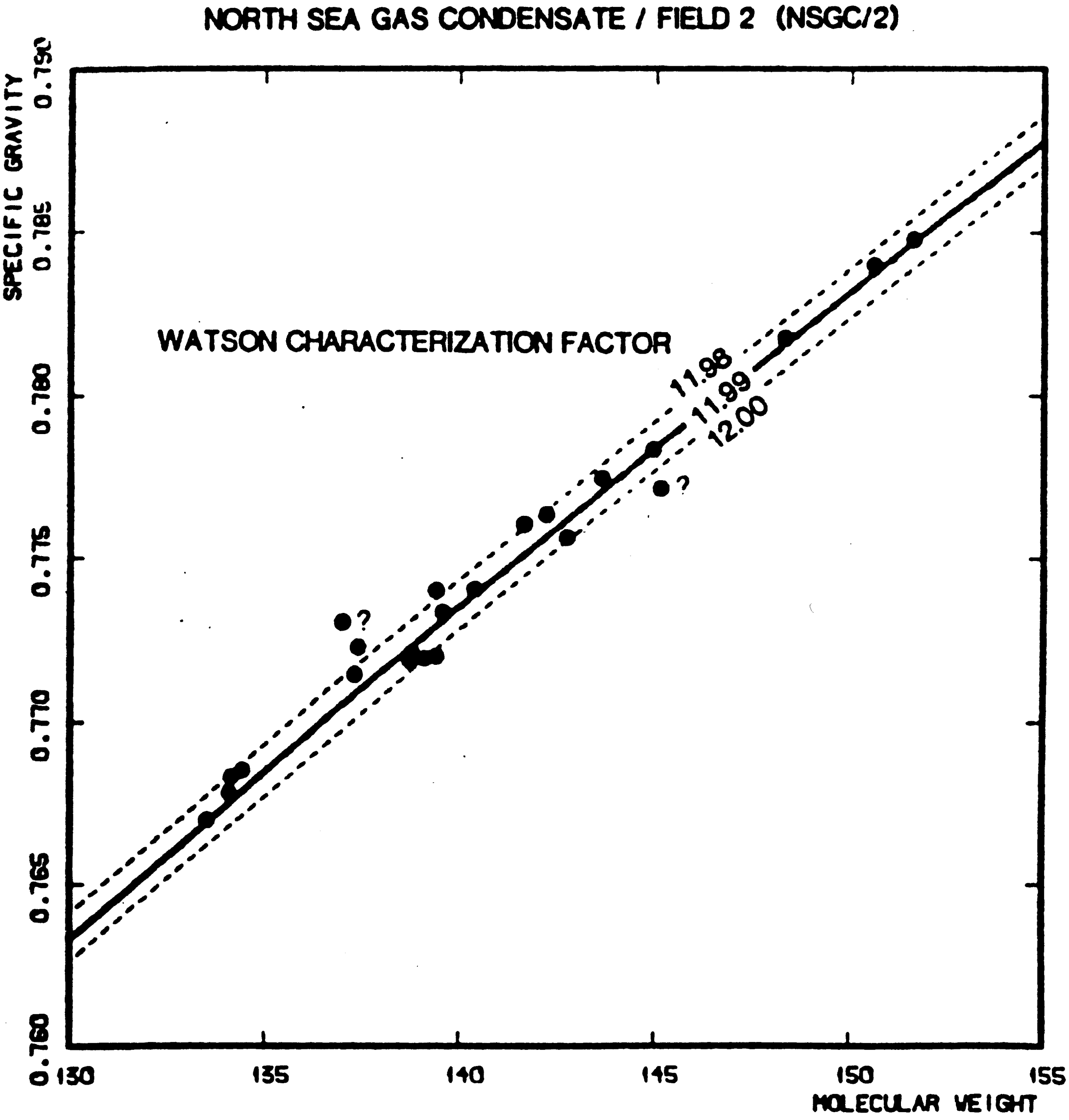

NORTH SEA GAS CONDENSATE / FIELD 2 (NSGC/2)
SPECIFIC GRAVITY
0.790
0.785
0.780
0.775
0.770
0.765
0.760
WATSON CHARACTERIZATION FACTOR
11.98
11.99
12.00
?
?
130
135
140
145
150
155
MOLECULAR WEIGHT

**Figure 3-37**

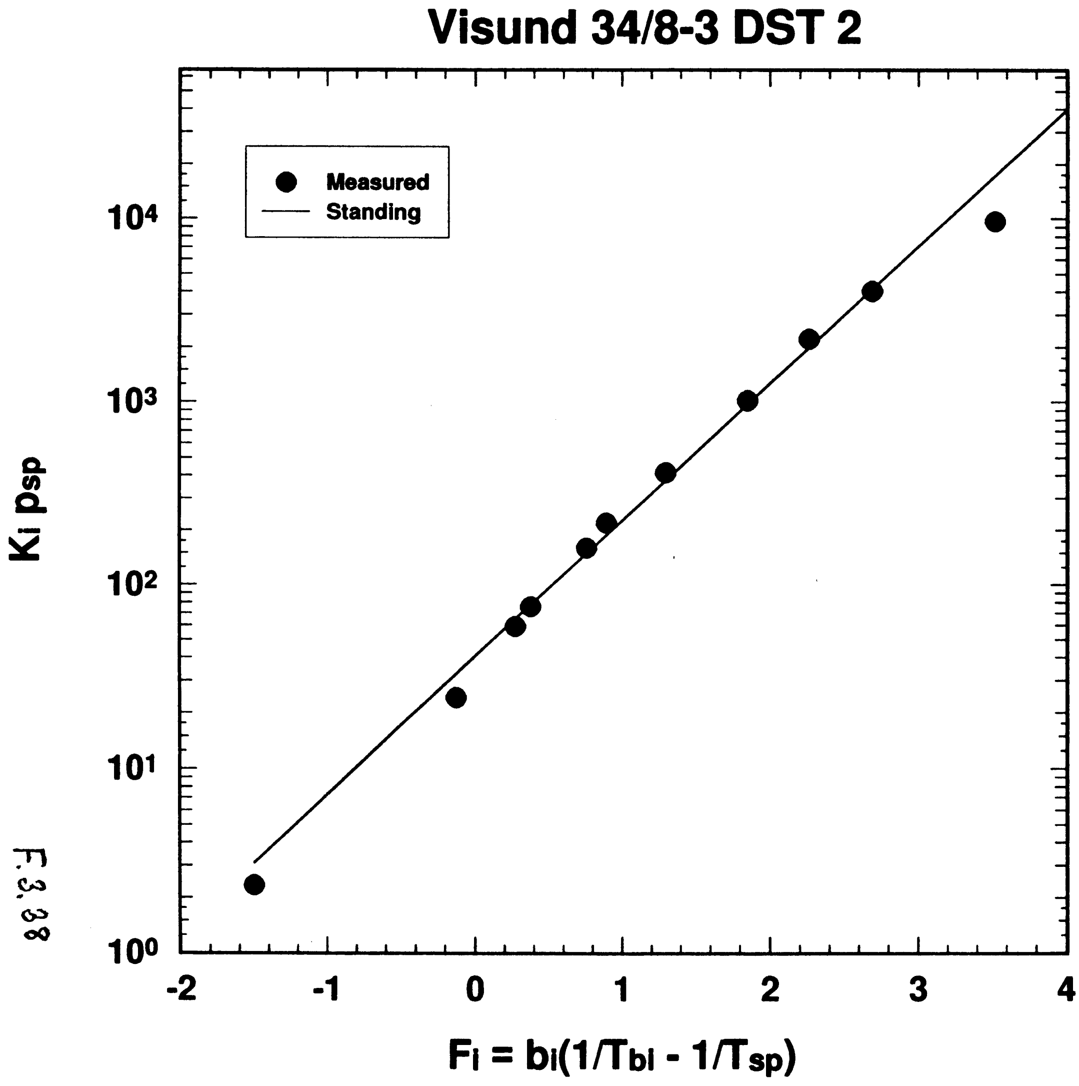
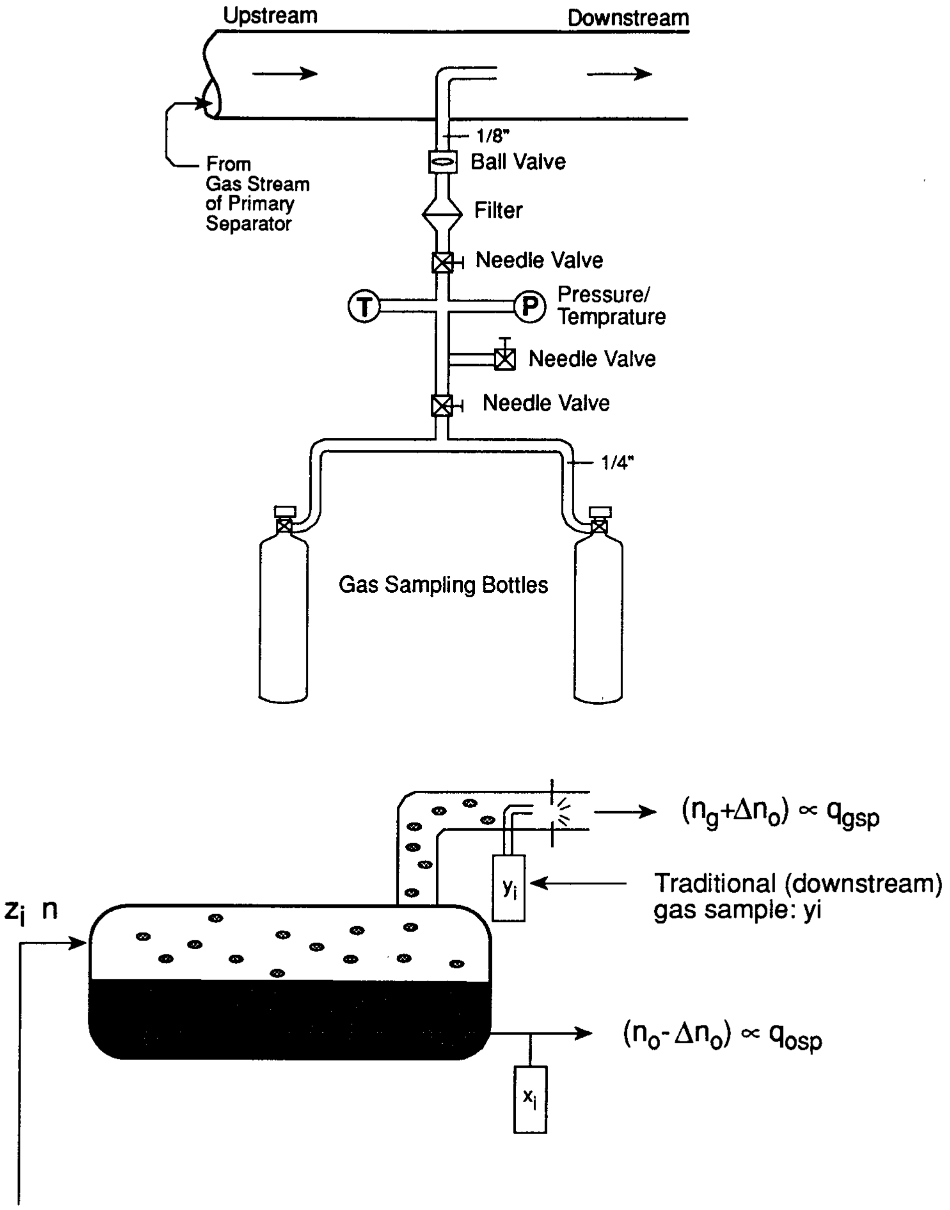

Visund 34/8-3 DST 2
Measured
Standing
$10^4$
$10^3$
$10^2$
$10^1$
$10^0$
$K_i p_{sp}$
-2
-1
0
1
2
3
4
$F_i = b_i(1/T_{bi} - 1/T_{sp})$
F.3.38

Figure 3-38



$$n\,z_i = n_g\,y_i + n_o\,x_i$$

$$= \underbrace{(n_g\,y_i + \Delta n_o\,x_i)}_{\begin{array}{c}\left(\begin{array}{c}\text{Separator Gas}\\+\\\text{Carryover}\end{array}\right)\\=\\\text{Isokinetic Gas}\\\text{Sample}\end{array}} + \underbrace{(n_o - \Delta n_o)\,x_i}_{\left(\begin{array}{c}\text{Separator Oil}\\-\\\text{Carryover}\end{array}\right)}$$

**Figure 3-39**

# 4. PVT REQUIREMENTS AND CORRELATIONS

## 4.1 Introduction

### 4.1.1 Where Do Measured PVT Data Come From?

In this chapter we look at how to use measured PVT data in reservoir calculations. Measured PVT data may include:

- Production data from a well test, including separator GOR, stock-tank oil and separator gas gravities ($\gamma_o$ and $\gamma_g$), and reservoir temperature.

- Standard laboratory PVT analyses (see chapter 3), including compositional analysis, constant composition expansion, a depletion experiment, and perhaps a multistage separator test.

- Special laboratory PVT analyses such as multiple-contact gas injection studies and slimtube displacements.

Production data will almost always be available from the initial discovery of a reservoir. Standard laboratory tests may take one to six months to obtain. Special PVT analyses may not be available for several years, as they are usually ordered only after gas injection has been deemed a viable development strategy.

### 4.1.2 Why Do We Need PVT Data?

All reservoirs require black-oil PVT properties for volumetric calculations. Most reservoirs will eventually be studied with a black-oil reservoir simulator. Some reservoirs may also require compositional simulation. The following list gives the primary applications of PVT data in reservoir calculations:

- Volumetric calculations of original gas and oil in place.

- Interpretation of well test and production data.

- Material balance calculations.

- Deliverability (inflow performance) calculations.

- Black-oil reservoir simulation of depletion, water injection, and some gas injection processes.

- Compositional (EOS) reservoir simulation of gas condensate and volatile oil systems, reservoirs with compositional variation, and gas injection processes.

- Compositional (EOS) process simulation

It is clear from this list that we must develop black-oil PVT properties for a reservoir as early as possible. In particular we need as a function of pressure: (1) volume factors $B_o$ and $B_g$, and (2) solution gas-oil ratio $R_s$ and/or oil-gas ratio $r_s$.

The saturation pressure of a reservoir fluid must also be determined as soon as possible. PVT properties are discontinous at the saturation pressure, and the reservoir production performance may be significantly different above and below the saturation pressure.

### 4.1.3 How do we get PVT Data?

PVT properties can be obtained from three primary sources:

- Empirical PVT correlations.
- Laboratory measurements.
- Equation of state fluid characterization.

Depending on the time since discovery, the type and size of the hydrocarbon accumulation, and the type of reservoir model being used, any or all three of these sources may be used to obtain the necessary PVT data.

*Empirical correlations* are useful in two situations. First, when the only information available is data from production tests. Correlations can be used to estimate the black-oil properties $B_o$, $B_g$, and $R_s$ as a function of pressure. A second application of correlations is to fit measured data from a given reservoir or field, using the developed correlations to interpolate and extrapolate PVT properties as a function of temperature and "composition" (e.g. STO gravity).

*Laboratory measured PVT data* can be used directly to determine black-oil properties for low- and moderately-volatile reservoir oils. The properties so derived ($B_o$, $B_g$, $R_s$, and sometimes $r_s$) relate surface oil and gas volumes for a specific set of separator conditions to volumes at reservoir conditions.

Laboratory measured PVT data can alternatively be used to tune an equation-of-state PVT model, with the resulting PVT model (hopefully) being able to generate more accurate black-oil properties for a wider range of reservoir compositions and temperatures.

*Equation of state models* can be fairly accurate for predictions of depletion-type processes, where the overall compositional effects are not large. Several equations of state characterization methods are even what might be termed "predictive," meaning that they predict saturation pressure, gas and oil densities and volumes with reasonable accuracy, based only on fluid composition and properties of the heaviest fraction (e.g. $C_{7+}$).

Usually the predictions of laboratory PVT data are not sufficiently accurate and adjustments to the EOS model must be made. This process may be difficult, even with automated nonlinear regression methods for modifying the EOS model. Usually, however, a match of the experimental data can be obtained. The resulting EOS model will then be valid for predicting depletion-type processes.

*A word of caution.* For an EOS model to accurately predict PVT behavior of systems with varying compositions, near-critical behavior, and developed miscibility processes, special care must be taken when tuning the EOS model. It is particularly important to include *all* available PVT data when tuning the EOS, including multi-contact gas injection experiments (e.g. swelling tests) and slimtube results if available.

### 4.1.4 Coming Up With PVT Data Can Be Difficult!

Many petroleum reservoirs recently discovered and currently being developed have rather complicated PVT behavior. For example, it is not uncommon that composition and PVT properties vary with depth, or that different geological formations in the same field produce significantly different fluids.

A result of this more complicated PVT behavior is that a field (or even a single geological formation) can not be described properly by a single set of PVT properties. Composition can vary. Saturation pressure can vary. Stock-tank oil gravity can vary. Producing GOR can vary. Reservoir temperature can vary.

Particular care must be given to how PVT properties are developed for reservoir modelling. Reservoir simulators may not be able to handle the multitude of PVT-related problems for some fields. This will demand continuing improvements in the PVT capabilities of reservoir simulators. But in lieu of these improvements, some improvisation may be required to solve our problems. For further discussion, see the Norsk Hydro publication "Handbok for Reservoar Simulering.[1]

## 4.2 Eclipse 100 PVT Formats

The following sections are taken directly from the ECL100 user's manual.[2] Alternate ECL100 PVT input formats (simplified oil and gas tables, PVCO and PVDG) are not given here but may be found in the ECL100 documentation.

Other EOS-based programs such as PVTSIM and Intera's PVT generate files using ECL100 (PVTO and PVTG) format. *Even with identical EOS characterizations, one fundamental difference will be found between how the various EOS programs generated ECL100 PVTO (and PVTG) data at pressures greater than the original saturation pressure.*

At pressures greater than the (original) saturation pressure, the various EOS programs may or may not extend (extrapolate) the saturated properties for $p>p_{sat}$. PVTx does not extend saturated properties beyond the original saturation pressure. This must be done manually, using different feeds with higher saturation pressures, and then "splicing" the ECL100 output files together. Section 5.4.5 (*Generating Modified Black-Oil PVT*) discusses this approach, and how other EOS programs extrapolate saturated PVT properties.

Basically, the recommended approach for extrapolating saturated data (if at all) depends on the reservoir process being simulated. Gas injection requires one approach, while compositional variation with depth requires another approach. Some gas injection processes cannot be modelled adequately using ECL100. Alternatives include using a more complicated black-oil PVT formulation such as found in the ECL200 "GI" approach, or using fully compositional (EOS) simulation.

### 4.2.1 PVTO - General Oil PVT Table

The ECL100 PVT table for saturated oil is specified with the **PVTO** command. A copy of the current version of the PVTO command from Intera's users manual is shown on the following page. It is recommended that the PVTO command be used instead of the alternative PVCO and PVDO commands, unless a particular application clearly calls for the use of an alternative PVT input format.

The PVTO table is automatically generated by PVTx using the PRINT ECL100 print keyword (with an optional unit specification), and by specifying multistage separator commands SEPA in at least one depletion experiment (CCE, CVD, and/or DLE). For example,

```
PRINT ECL100 SI
*
DLE FEED=1
DEGC BARA
TEMP=123
*     tsp   psp
SEPA   60    60
SEPA   25    15
SEPA   15.5   1.0135
DATA
 345  / psat
 500  / at least one pressure > psat must be input !!!
 400
 350
 325
 300
 ...
/end
```

Note, at least one pressure greater than the calculated saturation pressure must be input when generating ECL100 PVT files.

Don't forget to put the ECLIPSE file-opening command in the file **pvtxfil**.

**PVTO**

## PVT properties of live oil (With dissolved gas)

○ RUNSPEC
○ GRID
○ EDIT
● PROPS
○ REGIONS
○ SOLUTION
○ SUMMARY
○ SCHEDULE

The data comprises NTPVT (see RUNSPEC section) tables of live oil PVT functions. A single table consists of at least 2 and up to NRPVT (see RUNSPEC section) records each terminated by a slash (/). Each record gives PVT data for a particular dissolved gas-oil ratio ($R_s$). A table is terminated by a null record (i.e a record with no data before the terminating slash).

Most records contain 4 numbers and a terminating slash:

Item 1 The dissolved gas-oil ratio ($R_s$).
Within a table, records should be arranged in order of increasing $R_s$.

- UNITS: $SM^3/SM^3$ (METRIC), MSCF/STB (FIELD) or SCC/SCC (LAB).

Item 2 The bubble point pressure ($P_{bub}$) for oil with dissolved gas-oil ratio given by item 1.

- UNITS: BARSA (METRIC), PSIA (FIELD) or ATMOSA (LAB).

Item 3 The oil formation volume factor for saturated oil at $P_{bub}$.

- UNITS: $RM^3/SM^3$ (METRIC), RB/STB (FIELD) or RCC/SCC (LAB).

Item 4 The oil viscosity for saturated oil at $P_{bub}$.

- UNITS: CentiPOISE cP(for METRIC, FIELD and LAB).

However some records (optionally all) contain additional data which defines the properties of under-saturated oil at the specified value of $R_s$. This extra data **must** be specified for the highest $R_s$ in each table. The additional data takes the form of 3 columns which continue from items 2, 3 and 4 above. Each column may have up to NPPVT (see RUNSPEC) entries.

Column 2 The oil phase pressure ($P_o$).
Values of $P_o$ must increase down the column (starting from $P_{bub}$).

- UNITS: BARSA (METRIC), PSIA (FIELD) or ATMOSA (LAB).

Column 3 The oil formation volume factor ($B_o$) corresponding to $R_s$ and $P_o$.
Values of $B_o$ must decrease down the column.

- UNITS: $RM^3/SM^3$ (METRIC), RB/STB (FIELD) or RCC/SCC (LAB).

Column 4 The oil viscosity ( $\nu_o$) corresponding to $R_s$ and $P_o$.
Values of $\nu_o$ do not normally decrease down the column.

- UNITS: CentiPOISE (for metric, field and lab).

There must be the same number of entries in each column. If no additional data is supplied for a particular value of $R_s$, *Eclipse* locates the next higher value of $R_s$ for which undersaturated PVT data is available, and takes a scaled copy of the FVF and viscosity curves supplied there. The scaling is done in such a way that the compressibility and 'viscosibility',

$$\frac{d\nu_o}{dP_o} / \nu_o$$

are preserved.

Note that data for undersaturated oil **must** be provided for the highest $R_s$ in the table.

**Note:** *Eclipse* linearly interpolates the **reciprocals** of $B_o$ and ( $B_o \nu_o$) between data points, rather than the values themselves.
This should be taken into account when comparing the results of *Eclipse* with those of other simulators, by ensuring the data points are not distributed too sparsely.

See also keyword PVCO.

### 4.2.2 PVTG - General Gas PVT Table

The ECL100 PVT table for saturated gas (including "vapourized oil", i.e. dissolved condensate) is specified with the **PVTO** command. A copy of the current version of the PVTG command from Intera's users manual is shown on the following page. It is recommended that the PVTG command be used instead of the alternative PVDG command, unless the particular application clearly calls for the use of PVDG (the gas is truly "dry").

The PVTG table is automatically generated by PVTx using the PRINT ECL100 print keyword (with optional unit definition), and by specifying multistage separator commands SEPA in at least one depletion experiment (CCE, CVD, or DLE). For example,

```
PRINT ECL100 SI
*
CVD FEED=1
DEGC BARA
TEMP=136
*     tsp   psp
SEPA   50    45
SEPA   23    12
SEPA   15.5   1.0135
DATA
 382  / psat
 500  / at least one pressure > psat must be input !!!
 400
 350
 325
 300
 ...
/end
```

Note, at least one pressure greater than the calculated saturation pressure must be input when generating ECL100 PVT files.

Don't forget to put the ECLIPSE file-opening command in the file **pvtxfil**.

**PVTG**

## PVT properties of wet gas (With vapourised oil)

○ RUNSPEC
○ GRID
○ EDIT
● PROPS
○ REGIONS
○ SOLUTION
○ SUMMARY
○ SCHEDULE

The data comprises NTPVT (see RUNSPEC section) tables of wet gas PVT functions. A single table consists of at least 2 and up to NPPVT (see RUNSPEC section) records each terminated by a slash (/). Each record gives PVT data for a particular gas phase pressure ($P_g$). A table is terminated by a null record (i.e a record with no data before the terminating slash).

Most records contain 4 numbers and a terminating slash:

Item 1 The gas phase pressure ($P_g$).
Within a table, records should be arranged in order of increasing $P_g$.

- UNITS: BARSA (METRIC), PSIA (FIELD) or ATMOSA (LAB).

Item 2 The vapourised oil-gas ratio for saturated gas at pressure $P_g$.

- UNITS: $SM^3/SM^3$ (METRIC), STB/MSCF (FIELD) or SCC/SCC (LAB).

Item 3 The gas formation volume factor for saturated gas at $P_g$.

- UNITS: $RM^3/SM^3$ (METRIC), RB/MSCF (FIELD) or RCC/SCC (LAB).

Item 4 The gas viscosity for saturated gas at $P_g$.

- UNITS: CentiPOISE cP(for METRIC, FIELD and LAB).

However some records (optionally all) contain additional data which defines the properties of under-saturated gas at the specified value of $P_g$. This extra data **must** be specified for the highest $P_g$ in each table. The additional data takes the form of 3 columns which continue from items 2, 3 and 4 above.

Each column may have up to NRPVT (see RUNSPEC) entries.

Column 2 The vapourised oil-gas ratio ($R_v$).
Values of Rv must decrease down the column (starting from the value for saturated gas).

- UNITS: $SM^3/SM^3$ (METRIC), STB/MSCF (FIELD) or SCC/SCC (LAB).

Column 3 The gas formation volume factor ($B_g$) corresponding to $R_v$ and $P_g$.

- UNITS: $RM^3/SM^3$ (METRIC), RB/MSCF (FIELD) or RCC/SCC (LAB).

Column 4 The gas viscosity ($v_g$) corresponding to $R_v$ and $P_g$.

- UNITS: CentiPOISE (for METRIC, FIELD and LAB).

There must be the same number of entries in each column. If no additional data is supplied for a particular value of $P_g$, *Eclipse* locates the next higher value of $P_g$ for which undersaturated PVT data is available, and takes a scaled copy of the FVF and viscosity curves supplied there.

**Note:** Data for undersaturated gas **must** be provided for the highest $P_g$ in the table.

### 4.2.3 PVTW - General Water PVT Table

Water properties are input to ECL100 using the water PVT table PVTW. This input basically consists of specifying a reference pressure (e.g. initial reservoir pressure), water FVF and viscosity at the reference pressure, and water compressibility and "viscosibility" at the reference pressure.

These data can be obtained from generalized correlations in the Fluid Data Book (Charts x-x), or for a specific reservoir system using the BIPWAT Lotus 1-2-3 spreadsheet and PVTx (see section 5.8 for an example of the latter).

## **PVTW** Water PVT Functions

○ RUNSPEC
○ GRID
○ EDIT
● PROPS
○ REGIONS
○ SOLUTION
○ SUMMARY
○ SCHEDULE

The data comprises `NTPVT` (see `RUNSPEC` section) records, each terminated by a slash (/).

Each record consists of 5 items of data:

Item 1 The reference pressure ($P_{ref}$) for items 2 and 4.

- UNITS: BARSA (`METRIC`), PSIA (`FIELD`) or ATMOSA (`LAB`).

Item 2 The water formation volume factor at the reference pressure, $B_w(P_{ref})$

- UNITS: RM$^3$/SM$^3$ (`METRIC`), RB/STB (`FIELD`) or RCC/SCC (`LAB`).

Item 3 The water compressibility

$$C = -\left(\frac{dB_w}{dP}\right)/B_w$$

- UNITS: 1/BARS (`METRIC`), 1/PSI (`FIELD`) or 1/ATMOS (`LAB`).

Item 4 The water viscosity at the reference pressure $\nu_w(P_{ref})$.

- UNITS: CPOISE (`METRIC`), CPOISE (`FIELD`) or CPOISE (`LAB`).

Item 5 The water "viscosibility"

$$C_v = -\left(\frac{d\nu_w}{dP}\right)/\nu_w$$

- UNITS: 1/BARS (`METRIC`), 1/PSI (`FIELD`) or 1/ATMOS (`LAB`).

*Eclipse* calculates $B_w$ using:

$$B_w(P) = \frac{B_w(P_{ref})}{1 + X + (X^2/2)}$$

where $X = C(P - P_{ref})$

and the product $B_w\nu_w$ using:

$$B_w\nu_w(P) = \frac{B_w(P_{ref})\nu_w(P_{ref})}{1 + Y + (Y^2/2)}$$

where $Y = (C - C_v)(P - P_{ref})$

# 4.3 PVT Data from Production Test Results

### 4.3.1 What Data Are Available?

Results from production testing of a discovery oil well will provide sufficient information to generate a complete set of PVT data for most reservoir engineering calculations, including screening simulation studies. The basic data required are:

- Reservoir temperature, $T_R$
- Stock-tank oil gravity, $\gamma_o$
- Total average surface gas gravity, $\gamma_g$
- Producing (solution) gas-oil ratio, $R_s$

Reservoir temperature is measured during logging and pressure transient tests. Separator gas and oil measurements are made on site during production testing.

### 4.3.2 Separator Rates

Field measurement of GOR is based on test separator gas rate given as a standard gas volume (at 1 atm and 15 $^oC$), and either (a) separator oil rate reported at separator conditions, or (b) stock-tank oil rate. Table 3-12 gives corrections for separator gas rates that influence the recombination GOR used for calculating the wellstream composition.

The relation between stock-tank oil rate and separator oil rate is given by a shrinkage factor, the inverse of separator oil FVF ($b_{osp}=1/B_{osp}$),

$$Shrinkage = \frac{1}{B_{osp}} = b_{osp} = \frac{volume\ stock\text{-}tank\ oil}{volume\ oil\ at\ separator\ conditions}$$

The shrinkage factor $b_{osp}$ usually ranges from 0.8 to 0.95 for offshore test separator conditions. It is important to determine which oil rate has actually been reported in a given test.

Stock-tank oil rates are usually denoted SM3/D or STB/D, although it is not uncommon that they are misleadingly labeled M3/D or BBL/D. Separator rates are usually denoted M3/D or BBL/D. If you are lucky, both rates are reported, together with the shrinkage factor used. If in doubt about what oil rate is reported, ask the well testing engineer or call the testing/sampling company who reported the rate.

The oil rate equation that yields stock-tank volumetric rate $q_o$ from metered test separator rate $q_{meter}$ is

$$q_o = q_{meter}\ C_{meter}\ b_{osp}\ (1 - f_{BSW})$$

where $C_{meter}$ is a correction to the meter reading (calibration factor), and $f_{BSW}$ is the BS&W (basic sediments and water) fraction.

In closing, several precautions should be made to obtain a representative GOR. First, the well should be produced at sufficiently high rates to ensure stable flow conditions. The GOR should be constant or changing smoothly and gradually on a fixed choke. *It is more important to have a stable GOR condition with a higher rate, than to maintain a high wellbore flowing pressure to avoid two-phase flow near the wellbore.*

### 4.3.3 Using Separator Test Data

Before separator test data from an oil well can be used in PVT correlations it is necessary to estimate surface data that are not usually measured. Figure 4-1 illustrates a typical separator test, where measured and calculated data are indicated. Measured data usually include:

- First stage separator gas rate, $q_{g1}$, Sm$^3$/d
- First stage separator oil rate, $q_{osp}$, sep. m$^3$/d, or stock-tank oil rate, $q_o$, Sm$^3$/d
- First stage separator gas gravity, $\gamma_{g1}$
- Stock-tank oil gravity, $\gamma_o$

Shrinkage ($1/B_{osp}$) is either measured or estimated from a correlation.

Based on the reported test information, the following additional quantities should be calculated:

1. Additional gas in solution in separator oil, $R_{s+}$ (scf/STB), and the specific gravity of the solution gas, $\gamma_{g+}$

$$R_{s+} = \frac{A_1 A_2}{(1 - A_1 A_3)} \qquad (4\text{-}1)$$

$$\gamma_{g+} = A_2 + A_3 \ R_{s+}$$

where

$$A_1 = \left[ \left( \frac{p_{sp1}}{18.2} + 1.4 \right) 10^{(0.0125\gamma_{API} - 0.00091 T_{sp1})} \right]^{1.205} \qquad (4\text{-}2)$$

$$A_2 = 0.25 \ + \ 0.02\,\gamma_{API}$$

$$A_3 = -\,3.57(10^{-6})\,\gamma_{API} \qquad (4\text{-}3)$$

with $p_{sp}$ given in psia and $T_{sp}$ given in $^{o}$F.

2. Separator oil volume factor, $B_{osp}$ (if not reported)

$$B_{osp} = 0.9759 + 12(10^{-5})\,A^{1.2}$$

$$A = R_{s+}\left(\frac{\gamma_{g+}}{\gamma_o}\right)^{0.5} + 1.25\,T_{sp} \qquad (4\text{-}4)$$

with $R_{s+}$ given in scf/STB and $T_{sp}$ given in $^{o}$F.

3. First stage separator GOR relative to STO, $R_{s1}$ (if not reported)

$$R_{s1} = \frac{q_{g1}}{q_o} = R_{sp1}\;B_{osp} \qquad (4\text{-}5)$$

4. Total solution gas-oil ratio, $R_s$

$$R_s = R_{s1} + R_{s+} \qquad (4\text{-}6)$$

5. Total average gas specific gravity $\bar{\gamma}_g$

$$\bar{\gamma}_g = \frac{\gamma_{g1}\;R_{s1} + \gamma_{g+}\;R_{s+}}{R_{s1} + R_{s+}} \qquad (4\text{-}7)$$

The quantities $R_s$, $\bar{\gamma}_g$, $\gamma_o$ (or $\gamma_{API}$) and reservoir temperature are used in the oil correlations discussed below.

## 4.4 Oil PVT Correlations

This section discusses how to use PVT correlations to generate PVT data used in reservoir engineering calculations, including black-oil data for reservoir simulation.

Oil PVT correlations are useful in several situations. Primarily we use them for estimating key PVT properties of new discoveries, before laboratory PVT data are available (one to six months after discovery). Correlations also can be used to fit measured PVT data, with the intention of interpolating and extrapolating in temperature and composition (i.e. API gravity). Finally, oil PVT correlations are often used for production calculations (e.g. pressure loss in tubing) and estimating separator oil shrinkage factors; PVT properties are required at temperatures lower than studied in the standard PVT tests conducted at reservoir temperature.

### 4.4.1 Solution Gas-Oil Ratio

The variation in solution GOR with pressure, $R_s(p)$, can be estimated from a bubblepoint pressure correlation. The traditional form of bubblepoint pressure correlations is

$$p_b = f\ (R_s, T, \gamma_o, \gamma_g)$$

For example, the Standing correlation[3] is

$$p_b = 18.2(A-1.4)$$
$$A = (\frac{R_s}{\gamma_g})^{0.83} \times 10^{0.00091T\ -\ 0.0125\gamma_{API}} \qquad (4\text{-}8)$$

The Glasø correlation[4] is also recommended, as it was developed for North Sea fields. The Lasater correlation[5] is also recommended.

Assuming a saturated condition at some pressure p, this relation can be solved for $R_s$,

$$R_s = F\ (p, T, \gamma_o, \gamma_g)$$

where F is the inverse function of f. The pressure p can be less than or greater than the original bubblepoint pressure predicted at reservoir temperature.

For the Standing bubblepoint correlation, $R_s(p)$ is given by

$$R_s = \gamma_g \left( \frac{(0.055p+1.4)10^{0.0125\gamma_{API}}}{10^{0.00091T}} \right)^{1.205} \qquad (4\text{-}9)$$

with p in psia, T in °F, and $R_s$ in scf/STB.

### 4.4.2 Solution GOR Above Initial Bubblepoint Pressure

Usually the solution GOR is assumed constant at pressures greater than the original bubblepoint pressure. However, this is strictly true only when the pressure decreases monotonically. Two situations in a reservoir may cause the oil to be saturated with more gas than originally in solution:

- Gas is injected at a pressure above the initial bubblepoint.
- Pressure builds up in a region of the reservoir with relatively high gas saturation (e.g. near the wellbore, or at the top of a layer undergoing gravity segregation).

In either situation, the oil can locally become saturated with more gas than originally in solution.

2 illustrates the behavior of $R_s(p)$. The upper figure shows the behavior that will be predicted by most empirical PVT correlation, where a monotonic relationship exists between $R_s$ and pressure. The only correlation that does not give an approximately linear increase in $R_s$ with pressure is the Lasater correlation, which has the limiting condition $p=0.84T/\gamma_g$ for infinite $R_s$ (T is in

$^o$R and p is in psia).

The lower figure shows the actual behavior that would be expected for a leaner gas and a richer gas dissolving into a reservoir oil. A "rich" gas might be primary separator gas, and a "lean" gas might be a highly-processed, methane-rich gas. Several points are worth noting.

- Lean gas elevates the bubblepoint faster (more readily) than a rich gas. Therefore it takes more rich gas to elevate the bubblepoint to a given pressure.
- Extrapolating the $R_s(p)$ curve with an empirical bubblepoint correlation will result in a function that is more applicable to a "richer" gas.
- A critical point is reached where the addition of more gas results in a mixture exhibiting a dewpoint instead of a bubblepoint.
- The $R_s(p)$ is not monotonic forever. A maximum pressure will eventually be reached for most systems.
- The arrows indicate the *initial* direction that will be traversed on a particular curve. However, depending on the situation, it is possible to move either direction on any of the curves.

### 4.4.3 Saturated Oil Volume Factor

Saturated oil FVF correlations are given by a function of the form

$$B_{ob} = f\ (R_s, T, \gamma_o, \gamma_g)$$

Subscript *b* indicates that the oil is saturated at the current pressure, which is the bubblepoint pressure of the oil, containing dissolved gas given by $R_s$. Note that pressure does not enter the calculation of $B_{ob}$ directly, but only indirectly through $R_s(p)$.

The Standing correlation[3] for $B_{ob}$ is given as

$$\begin{aligned} B_{ob} &= 0.9759 + 12(10^{-5})\,A^{1.2} \\ A &= R_s\left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25T \end{aligned} \qquad (4\text{-}10)$$

The Glasø correlation[4], developed for North Sea reservoirs, is also recommended.

Referring now to Figure 4-2, the saturated part of the curve is shown with a solid line and dashed lines are used for the undersaturated states. The saturated oil FVF must be calculated along the solid line using an appropriate correlation.

### 4.4.4 Undersaturated Oil FVF and Compressibility

The oil FVF can be very important to the reservoir performance of highly-undersaturated oils. In fact, pressure depletion and recovery of these reservoirs are almost solely determined by $B_o$ (in the absense of water drive).

Undersaturated oil FVF is calculated from undersaturated oil compressibility. With several simplifying assumptions, the common relation

$$B_o \approx B_{ob}[1 - c_o(p - p_b)] \qquad (4\text{-}11)$$

can be derived. In this relation $c_o$ is assumed to be constant for all pressures greater than the bubblepoint. The result is a linear relationship between $B_o$ and p for $p>p_b$. This assumption is not really valid for oils with GOR>150 $Sm^3/Sm^3$.

The Vazquez correlation[6] for undersaturated oil compressibility is frequently used,

$$\begin{aligned} c_o &= A/p \\ A &= (5R_{sb} + 17.2T - 1180\gamma_{gc} + 12.61\,\gamma_{API} - 1433)\times 10^{-5} \end{aligned} \qquad (4\text{-}12)$$

with p in psia, T in $^o$F, and $R_s$ in scf/STB. $\gamma_{gc}$ is a corrected separator gas gravity given by

$$\gamma_{gc} = \gamma_g\ [1 + 0.5912(10^{-4})\ \gamma_{API}\, T_{sp} \log(\frac{p_{sp}}{114.7})] \qquad (4\text{-}13)$$

with $T_{sp}$ in $^o$F and $p_{sp}$ in psia. McCain[7] notes that this correlation tends to underpredict oil compressibility, particularly at highly undersaturated conditions.

Using the pressure depedence given by the Vazquez correlation, an exact relation for undersaturated oil FVF relation can be derived from the definition of isothermal compressibility, c=-(dV/dp)/V,

$$\begin{aligned} B_o &= B_{ob} \exp[\int_p^{p_b} c_o(p)\,dp] \\ &= B_{ob} \exp[A \int_p^{p_b} \frac{1}{p}\ dp] \end{aligned} \qquad (4\text{-}14)$$

resulting in

$$B_o = B_{ob}(p_b/p)^A \qquad (4\text{-}15)$$

where A is given by the Vazuez correlation (Eq. (4-12)), or determined from experimental data (e.g. from the slope of a log-log plot of $V_o/V_{ob}$ versus $p/p_b$).

For highly undersaturated, light-oil reservoirs (e.g. Embla Field), undersaturated $B_o$ can be significantly nonlinear (Figure 4-2). For such reservoirs the integral relation above should be used for oil FVF, where the pressure dependence of $c_o$ is taken into account.

### 4.4.5 Oil Density

Density of reservoir oil varies from 0.5 g/cm$^3$ for light volatile oils to 0.95 g/cm$^3$ for heavy crudes with little or no solution gas. Several methods have successfully been used to correlate oil density, including extensions of ideal-solution mixing, equations of state, corresponding-states correlations, and empirical correlations.

Oil density based on black-oil properties is given by

$$\rho_o = \frac{1000\gamma_o + 1.224\gamma_g \ R_s}{B_o} \tag{4-16}$$

with $\rho_o$ in kg/m$^3$, $B_o$ in m$^3$/Sm$^3$, and $R_s$ in Sm$^3$/Sm$^3$. Correlations can be used to estimate $R_s$ and $B_o$ from $\gamma_o$, $\gamma_g$, pressure, and temperature.

### Standing-Katz Method

Standing and Katz[3,8,9] give an accurate method for estimating oil densities using an extension of ideal-solution mixing,

$$\rho_o = \rho_{po} + \Delta\rho_p - \Delta\rho_T \tag{4-17}$$

where $\rho_{po}$ is the pseudoliquid density at standard conditions, and the terms $\Delta\rho_T$ and $\Delta\rho_p$ give corrections for temperature and pressure, respectively.

Pseudoliquid density is calculated using ideal-solution mixing and correlations for the apparent liquid densities of ethane and methane at standard conditions. Given oil composition $x_i$, $\rho_{po}$ is calculated from

$$\rho_{po} = \frac{\sum_{i=1}^{N} x_i M_i}{\sum_{i=1}^{N} \frac{x_i M_i}{\rho_i}} \tag{4-18}$$

where Standing and Katz show that apparent liquid densities $\rho_i$ (kg/m$^3$) of $C_2$ and $C_1$ are a function of the densities $\rho_{2+}$ and $\rho_{po}$ (also in kg/m$^3$), respectively (Chart x, Fluids Data Book),

$$\begin{aligned} \rho_2 &= 245.1 + 0.3167 \ \rho_{2+} \\ \rho_1 &= 4.998 + 0.45 \ \rho_{po} \end{aligned} \tag{4-19}$$

where

$$\rho_{2+} = \frac{\sum_{i=C_2}^{C_{7+}} x_i M_i}{\sum_{i=C_2}^{C_{7+}} \frac{x_i M_i}{\rho_i}} \tag{4-20}$$

Application of these correlations results in an apparent trial-and-error calculation for $\rho_{po}$. Standing[10] presents a graphical correlation (Chart x, Fluids Data Book) based on these relations, where $\rho_{po}$ is found from $\rho_{3+}$ and weight fractions of $C_2$ and $C_1$ ($w_2$ and $w_1$).

The pressure correction $\Delta\rho_p$ is a function of $\rho_{po}$, and $\Delta\rho_T$ is a function of $(\rho_{po}+\Delta\rho_p)$. Madrazo[11] introduced modified curves for $\Delta\rho_p$ and $\Delta\rho_T$ which improve predictions at higher pressures and temperatures. Standing[3] gives best-fit equations for his original graphical correlations of $\Delta\rho_p$ and $\Delta\rho_T$,

$$\begin{aligned}\Delta\rho_p &= 0.2323\ \left[0.167 + 16.181\left(10^{-0.00265\rho_{po}}\right)\right]\ p \\ &- 3.364\times10^{-5}\ \left[0.299 + 263\left(10^{-0.00376\rho_{po}}\right)\right]\ p^2\end{aligned} \tag{4-21}$$

$$\begin{aligned}\Delta\rho_T &= 16.02\ \ (1.8\,T - 28)\ \left[0.0133 + 1.363\times10^5\left(\rho_{po} + \Delta\rho_p\right)^{-2.45}\right] \\ &- 16.02\ \ (1.8\,T - 28)^2\ \left[8.1\left(10^{-6}\right) - 0.0622\times10^{-0.00477(\rho_{po}+\Delta\rho_p)}\right]\end{aligned} \tag{4-22}$$

with $\rho$ in kg/m$^3$, p in bara, and T in $^o$C. These equations are not recommended at temperatures greater than 115$^o$C; instead, Madrazo's graphical correlation can be used. The correction factors can also be used to determine isothermal compressibility and oil formation volume factor at undersaturated conditions.

The treatment of nonhydrocarbons in the Standing-Katz method has not received much attention, and the method is not recommended when concentrations of nonhydrocarbons exceed 10 mole percent. Standing[3] suggests that an apparent liquid density of 479 kg/m$^3$ can be used for nitrogen, but he does not address how the nonhydrocarbons should be considered in the calculation procedure - i.e., as part of the $C_{3+}$ material or following the calculation of $\rho_2$ and $\rho_1$. Madrazo indicates that the volume contribution of nonhydrocarbons can be neglected completely if the total content is less than 6 mole percent. Vogel and Yarborough[12] suggest the weight fraction of nitrogen should be added to the weight fraction of ethane.

In the absence of oil composition, Katz[13] suggests that the pseudoliquid density $\rho_{po}$ (in kg/m$^3$) be calculated from stock-tank oil gravity $\gamma_o$, solution gas-oil ratio $R_s$, and apparent liquid density of the surface gas $\rho_{ga}$ taken from a graphical correlation (Chart x, Fluid Data Book),

$$\rho_{po} = \frac{1000\,\gamma_o + 1.224\ R_s\ \gamma_g}{1 + 1.224\dfrac{R_s\ \gamma_g}{\rho_{ga}}} \tag{4-23}$$

Standing gives an equation for $\rho_{ga}$,

$$\begin{aligned}\rho_{ga} &= 16.02\ [38.52\times 10^{-0.00326\gamma_{API}} \\ &+ (94.75 - 33.93 \log \gamma_{API}) \log \gamma_g]\end{aligned} \tag{4-24}$$

with $\rho_{ga}$ in kg/m$^3$ and $R_s$ in Sm$^3$/Sm$^3$.

The Alani-Kennedy[14] method for calculating oil density is a modification of the original van der Waals' EOS, with constants a and b given as functions of temperature for normal paraffins $C_1$ to $C_{10}$, and iso-butane; two sets of coefficients are reported for methane (for temperatures from 20° to 150°C, and from 150° to 240°C) and two sets for ethane (for temperatures from 38° to 120°C, and from 120° to 240°C). Lohrenz et al.[15] give Alani-Kennedy temperature-dependent coefficients for nonhydrocarbons $N_2$, $CO_2$, and $H_2S$.

The Alani-Kennedy method has been outdated by more predictive cubic equations of state, such as the Peng-Robinson or Soave-Redlich-Kwong EOS using volume translation.

Rackett[16] and Hankinson et al.[17,18] give accurate correlations for pure component saturated liquid densities, and although these correlations can be extended to mixtures, they have not been tested extensively for reservoir systems.

### Cubic EOS with Volume Translation

The Standing-Katz method is limited somewhat by a temperature constraint of about 250$^o$F. Given oil composition (and $C_{7+}$ molecular weight and specific gravity), the most general and accurate method for estimating densities (and other volumetric properties) is the PR or SRK EOS with volume translation.

It is highly recommended to use the default PVTx fluid characterizations generated using the PVTxIN data set generator program[a]; either the Whitson $C_{7+}$ splitting routine for the PR EOS, or the Pederen et al. $C_{7+}$ procedure for the SRK EOS. Three $C_{7+}$ fractions is recommended, as oil volumetric properties are not very sensitive to the total number of $C_{7+}$ fractions.

---

[a] The $C_{7+}$ characterization method, and particularly the correct use of volume translation dictates the accuracy of cubic EOS oil volumetric predictions. The volume translation coefficients are usually constants for pure components, determined by matching the saturated liquid density at $T=0.7T_c$, where the volume shift for $C_{7+}$ fractions is determined by matching the specific gravity of each fraction.

### 4.4.6 Saturated Oil Viscosity

Oil viscosity can not be estimated reliably, perhaps within ±30% at best. The recommend correlations are based on two criteria:

- The correlations should extrapolate reasonably for light and heavy stock-tank crudes.
- In the exploration phase, when little data is available, it is important to make conservative estimates of key reservoir parameters.

Most correlations have the functional form given by Chew and Connally[19],

$$\mu_{ob} = A_1(\mu_{oD})^{A_2} \tag{4-25}$$

where $\mu_{oD}$ is dead-oil viscosity estimated as a function of temperature and stock-tank oil gravity. $A_1$ and $A_2$ are functions of solution GOR, $R_s$.

The recommended correlation for $\mu_{oD}$ is given by Bergman[20],

$$\begin{aligned} \ln\ \ln(\mu_{oD}+1) &= a_0 + a_1 \ln(T+310) \\ a_0 &= 22.33 - 0.194\ \gamma_{API} + 0.00033\ \gamma_{API}^2 \\ a_1 &= -3.20 + 0.0185\ \gamma_{API} \end{aligned} \tag{4-26}$$

with $\mu_{oD}$ in cp and T in °F. This correlation is recommended because it is applicable at reservoir temperatures and at seabed temperatures approaching 0°C. The Glasø correlation[4] is also well suited for this wide temperature range,

$$\begin{aligned} \mu_{oD} &= 3.141(10^{10})T^{-3.444} \\ &\times(\log \gamma_{API})^{[10.313(\log T)-36.447]} \end{aligned} \tag{4-27}$$

with $\mu_{oD}$ in cp and T in °F. The Bergman correlation predicts dead-oil viscosities slightly higher than the Glaso correlation (Figure 4-2).

The recommended correlations for $A_1$ and $A_2$ are given by Aziz et al.[21],

$$\begin{aligned} A_1 &= 0.20 + 0.80\times 10^{-0.00081 R_s} \\ A_2 &= 0.43 + 0.57\times 10^{-0.00072 R_s} \end{aligned} \tag{4-28}$$

with $R_s$ in scf/STB. These correlations predict slightly higher viscosities than most other correlations (for $A_1$ and $A_2$). The functional form of the Aziz et al. correlations are well-behaved at high $R_s$ values, approaching constant values $A_1$=0.2 and $A_2$=0.43 (there is no physical meaning attached to these constants).

The Beggs and Robinson correlations[22] for $A_1$ and $A_2$, which are commonly used, also behave reasonably at high $R_s$ values. However, the Beggs and Robinson correlation predicts considerably lower saturated oil viscosities than the Aziz correlation for $R_s$<150 $Sm^3/Sm^3$ (see Figure 4-2).

### 4.4.7 Undersaturated Oil Viscosity and "Viscosibility"

Undersaturated oil viscosity is very nearly a linear function of pressure, even at high pressures and for relatively volatile oils. Two correlations are

$$\begin{aligned}\mu_o &= \mu_{ob}(p/p_b)^A \\ A &= 2.6\ p^{1.187}\ \exp(-11.513 - 8.98\times 10^{-5}p)\end{aligned} \tag{4-29}$$

recommended. The first, which is commonly used, is given by Vazquez[6], with p in psia and viscosities in cp.

The second correlation is given by Standing (originally as a chart[10], and later fit to the following equation[23]),

$$\frac{\mu_o - \mu_{ob}}{p - p_b} = 2.4\times 10^{-5}\ \mu_{ob}^{1.6} + 3.8\times 10^{-5}\ \mu_{ob}^{0.56} \tag{4-30}$$

with p in psia and viscosities in cp. Based on this correlation, undersaturated oil viscosity is a linear function of pressure, with the slope given as a function of bubblepoint oil viscosity $\mu_{ob}$. Note that the quantity "viscosibility" used in the ECL100/ECL200 models is given by (see Figure 4-2)

$$\begin{aligned}\text{Viscosibility} &= \frac{1}{\mu_{ob}}\left(\frac{d\mu_o}{dp}\right)_{p=p_b} \\ &\approx 2.4\times 10^{-5}\ \mu_{ob}^{0.6} + 3.8\times 10^{-5}\ \mu_{ob}^{-0.44}\end{aligned} \tag{4-31}$$

with viscosibility in 1/psi. Multiply by 14.5 to get 1/bar.

The Vazquez correlation predicts somewhat higher viscosities than the Standing correlation, up to about $p=2p_b$. At higher pressures, the Vazquez correlation may give considerably higher viscosities, as shown in Figure 4-2.

The Standing correlation is recommended in general. The Vazquez correlation may have an abrupt increase in viscosity at higher pressures, a behavior that cannot be readily explained physically. The Standing correlation is only slightly more optimistic (lower $\mu_o$ values) than the Vazquez correlation, the Standing correlation is simpler, and it extrapolates in a physically consistent manner at high pressures.

## 4.5 Gas PVT Correlations

This section gives correlations for PVT properties of natural gases, including:

- Gas Volumetric Properties - Review
- Z-factor Correlations
- Gas Pseudocritical Properties

- Wellstream Gravity of Wet Gases and Gas Condensates
- Gas Viscosity
- Total Volume Factor

### 4.5.1 Gas Volumetric Properties

Most gases at low pressure follow the ideal-gas law,

$$pV = nRT \tag{4-32}$$

where

$R$=10.73146 psia ft$^3$ $^o$R$^{-1}$ lbmol$^{-1}$
$R$=8.3143 kPa m$^3$ K$^{-1}$ kmol$^{-1}$
$R$=0.083143 bar m$^3$ K$^{-1}$ kmol$^{-1}$

Application of the ideal-gas law results in two useful engineering approximations.

First, the standard molar volume representing the volume occupied by one mole of gas at standard conditions is independent of the gas composition:

$$\begin{aligned}(v_g)_{sc} &= \frac{(V_g)_{sc}}{n} = \frac{RT_{sc}}{p_{sc}} \\ &= 379.5\ \text{scf} / \text{lbmol} \\ &= 23.69\ \text{Sm}^3 / \text{kmol}\end{aligned} \tag{4-33}$$

Second, the specific gravity of a gas defines the gas molecular weight,

$$\begin{aligned}\gamma_g &= \frac{(\rho_g)_{sc}}{(\rho_{air})_{sc}} = \frac{M_g}{M_{air}} = \frac{M_g}{28.97} \\ M_g &= 28.97\ \gamma_g\end{aligned} \tag{4-34}$$

For gas mixtures at moderate to high pressure or at low temperature the ideal-gas law does not hold because the volume of the constituent molecules, as well as their intermolecular forces, strongly affect the volumetric behavior of the gas.

$$pV = nZRT \tag{4-35}$$

The *real gas law* includes a correction term, the Z-factor,
This is the standard equation for describing the volumetric behavior of reservoir gases. All volumetric properties of gases can be derived from the real-gas law.

Gas density is given by

$$\rho_g = \frac{pM_g}{ZRT} = 28.97\frac{p\gamma_g}{ZRT} \tag{4-36}$$

For wet-gas and gas-condensate mixtures, wellstream gravity $\gamma_w$ should always be used instead of $\gamma_g$ in calculating pseudocritical properties.

Gas compressibility $c_g$ is given by

$$c_g = -\frac{1}{V_g}\left(\frac{\partial V_g}{\partial p}\right) \tag{4-37}$$

$$= \frac{1}{p} - \frac{1}{Z}\left(\frac{\partial Z}{\partial p}\right)_T$$

For sweet natural gas (i.e., not containing $H_2S$) at pressures less than about 70 bara, the second term in Eq. (4-37) is negligible and $c_g \approx 1/p$ is a reasonable approximation.

Gas volume factor $B_g$ is defined as the ratio of gas volume at specified p and T to the ideal-gas volume at standard conditions,

$$B_g = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{Z\ T}{p} \tag{4-38}$$

which for SI units ($p_{sc}$=1.013 bara and $T_{sc}$=15.56°C=288.7 K) is

$$B_g = 0.00351\frac{Z\ T}{p} \tag{4-39}$$

with temperature in K and pressure in bar.

Because $B_g$ is inversely proportional to pressure, the inverse volume factor $b_g=1/B_g$ is commonly used. For SI units (bara and K),

$$b_g(Sm^3/Sm^3) = 285\frac{p}{Z\ T} \tag{4-40}$$

### 4.5.2 Z-Factor and Compressibility

Standing and Katz[24] present a generalized Z-factor chart which has become an industry standard for predicting the volumetric behavior of natural gases. Many empirical equations and equations of state have been fit to the original Standing-Katz chart. For example, Hall and Yarborough[25] present an accurate representation of the Standing-Katz chart using a Carnahan-Starling hard-sphere equation of state,

$$Z = \frac{\alpha p_{pr}}{y}$$

$$\alpha = 0.06125\ t\ \exp[-1.2(1-t)^2] \tag{4-41}$$

$$t = 1/T_{pr}$$

where the reduced density y (the product of a van der Waals covolume and density) is obtained by solving the relation

$$\begin{aligned} F(y) = 0 = -\alpha p_{pr} + \frac{y + y^2 + y^3 - y^4}{(1-y)^3} \\ - (14.76\,t - 9.76\,t^2 + 4.58\,t^3)y^2 \\ + (90.7\,t - 242.2\,t^2 + 42.4\,t^3)y^{1.18+2.82t} \end{aligned} \tag{4-42}$$

with

$$\begin{aligned} \frac{dF}{dy} = \frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1-y)^4} - (29.52\,t - 19.52\,t^2 + 9.16\,t^3)\,y \\ + (2.18 + 2.82\,t)(90.7\,t - 242.2\,t^2 + 42.4\,t^3)\,y^{1.18+2.82t} \end{aligned} \tag{4-42}$$

The derivative $\partial Z/\partial p$ used in the definition of $c_g$ is given by

$$\left(\frac{\partial Z}{\partial p}\right)_T = \frac{\alpha}{p_{pc}}\left(\frac{1}{y} - \frac{\dfrac{\alpha p_{pr}}{y^2}}{\dfrac{dF}{dy}}\right) \tag{4-43}$$

An initial value of y=0.001 can be used with a Newton-Raphson procedure where convergence should be obtained in 3 to 10 iterations for $F(y)=10^{-8}$.

Based on Takacs[26] comparison of 8 correlations representing the Standing-Katz chart, the Hall-Yarborough and Dranchuk-Abou-Kassem[27] equations give the most accurate representation for a broad range of temperature and pressure. Both equations are valid for $1 \leq T_r \leq 3$ and $0.2 \leq p_r \leq 25\text{-}30$.

For many petroleum engineering applications the Brill and Beggs[28] equation gives a satisfactory representation (±1-2%) of the original Standing-Katz Z-factor chart for $1.2<T_r<2$. Also, this equation can be solved explicitly for Z. The main limitations are that reduced temperature must be greater than 1.2 (≈25°C) and less than 2.0 (≈170°C), and reduced pressure should be less than 15 (≈700 bara).

The Standing-Katz Z-factor correlation may require special treatment for wet gas and gas condensate fluids containing significant amounts of heptanes-plus material, and for gas mixtures with significant amounts of nonhydrocarbons. Also, several authors have noted an apparent discrepancy in the Standing-Katz Z-factor chart for $1.05<T_r<1.15$, which has been "smoothed" in the Hall-

Yarborough correlations.

The Hall-Yarborough (or the Dranchuk-Abou-Kassem) equation is recommended for most natural gases. With today's computing capabilities it is normally unnecessary to choose simple, less reliable equations such as the Brill and Beggs equation.

### 4.5.3 Gas Pseudocritical Properties

Z-factor, viscosity and other gas properties have been accurately correlated using corresponding-states principles, where the property is correlated in terms of reduced pressure and temperature:

$$\begin{aligned} Z &= f\ (p_r, T_r) \\ \mu_g / \mu_g^o &= f\ (p_r, T_r) \end{aligned} \qquad (4\text{-}44)$$

where $p_r = p/p_c$ and $T_r = T/T_c$. Such corresponding-states relations should be valid for most pure compounds when component critical properties $p_c$ and $T_c$ are used. The same relations can be used for gas mixtures if the mixture *pseudocritical* properties $p_{pc}$ and $T_{pc}$ are used. Pseudocritical properties of gases can be estimated using gas composition and mixing rules, or from correlations based on gas specific gravity.

Sutton[29] suggest the following correlations for *hydrocarbon* gas mixtures,

$$\begin{aligned} T_{pcHC} &= 169.2 + 349.5\gamma_{gHC} - 74.0\gamma_{gHC}^2 \\ p_{pcHC} &= 756.8 - 131\gamma_{gHC} - 3.6\gamma_{gHC}^2 \end{aligned} \qquad (4\text{-}45)$$

He claims his equations are reliable for calculating pseudocritical properties with the Standing-Katz Z-factor chart; he even suggests that this method is superior to using composition and mixing rules(?).

Kay's mixing rule[30] is typically used when gas composition is available,

$$\begin{aligned} T_{pc} &= \sum_{i=1}^{N} y_i \ T_{ci} \\ p_{pc} &= \sum_{i=1}^{N} y_i \ p_{ci} \end{aligned} \qquad (4\text{-}46)$$

where the pseudocritical properties of the $C_{7+}$ fraction can be estimated from the Matthews et al. correlations[3,31],

$$\begin{aligned} T_{c7+} &= 608 + 364 \log(M_{7+} - 71.2) \\ &\quad + (2450 \log M_{7+} - 3800) \log \gamma_{7+} \\ p_{c7+} &= 1188 - 431 \log(M_{7+} - 61.1) \\ &\quad + [2319 - 852 \log(M_{7+} - 53.7)](\gamma_{7+} - 0.8) \end{aligned} \qquad (4\text{-}47)$$

Kay's mixing rule is usually adequate for lean natural gases in the absense of nonhydrocarbons. Sutton suggests that pseudocriticals calculated using Kay's mixing rule are adequate up to $\gamma_g$_0.85, but that errors in calculated Z-factors increase linearly at higher specific gravities, reaching 10 to 15% for $\gamma_g>1.5$.

When significant quantities of nonhydrocarbons $CO_2$ and $H_2S$ are present, Wichert and Aziz[32] suggest corrections to arrive at pseudocritical properties that yield reliable Z-factors from the Standing-Katz chart. The Wichert and Aziz corrections are given by,

$$\begin{aligned} T_{pc} &= T^*_{pc} - \varepsilon \\ p_{pc} &= \frac{p^*_{pc}(T^*_{pc} - \varepsilon)}{T^*_{pc} + y_{H_2S}(1 - y_{H_2S})\varepsilon} \\ \varepsilon &= 120\,[\,(y_{CO_2} + y_{H_2S})^{0.9} - (y_{CO_2} + y_{H_2S})^{1.6}\,] + 15(y^{0.5}_{H_2S} - y^{4}_{H_2S}) \end{aligned} \qquad (4\text{-}48)$$

where $T^*_{pc}$ and $p^*_{pc}$ are mixture pseudocriticals based on Kay's mixing rule. This method was developed from extensive data from natural gases containing nonhydrocarbons, with $CO_2$ molar concentration ranging from 0 to 55% and $H_2S$ ranging from 0 to 74%.

If only gas gravity and nonhydrocarbon content are known, the hydrocarbon specific gravity is first calculated from

$$\gamma_{gHC} = \frac{\gamma_g - (y_{N_2} M_{N_2} + y_{CO_2} M_{CO_2} + y_{H_2S} M_{H_2S}) / M_{air}}{1 - y_{N_2} - y_{CO_2} - y_{H_2S}} \qquad (4\text{-}49)$$

Hydrocarbon pseudocriticals are then calculated from Eqs. (4-45), and these values are adjusted for nonhydrocarbon content based on Kay's mixing rule,

$$\begin{aligned} p^*_{pc} &= (1 - y_{N_2} - y_{CO_2} - y_{H_2S})\, p_{pcHC} \\ &\quad + y_{N_2} p_{cN_2} + y_{CO_2} p_{cCO_2} + y_{H_2S} p_{cH_2S} \\ T^*_{pc} &= (1 - y_{N_2} - y_{CO_2} - y_{H_2S})\, T_{cHC} \\ &\quad + y_{N_2} T_{cN_2} + y_{CO_2} T_{cCO_2} + y_{H_2S} T_{cH_2S} \end{aligned} \qquad (4\text{-}50)$$

$T^*_{pc}$ and $p^*_{pc}$ are used in the Wichert-Aziz equations using $CO_2$ and $H_2S$ mole fractions to obtain mixture $T_{pc}$ and $p_{pc}$.

The Sutton correlations (Eqs. 4-45)) are recommended for hydrocarbon pseudocritical properties. If composition is available, Kay's mixing rule should be used with the Matthews et al. pseudocriticals for $C_{7+}$. Gases containing significant amounts of nonhydrocarbons $CO_2$ and $H_2S$ should always be corrected using the Wichert-Aziz equations. Finally, for gas-condensate fluids the wellstream gravity $\gamma_w$ (discussed below) should replace $\gamma_g$ in the equations above.

### 4.5.4 Wellstream Gravity

Gas mixtures that produce condensate at surface conditions usually exist as a single phase gas in the reservoir and production tubing. This can be verified by determining the dewpoint pressure at the prevailing temperature. If properties of the wellstream are desired at conditions where the mixture is single-phase, it is necessary to convert surface gas and surface oil properties to a wellstream specific gravity $\gamma_w$. This gravity should be used instead of $\gamma_g$ to estimate pseudocritical properties.

Wellstream gravity represents the average molecular weight of the produced mixture (relative to air) and it is readily calculated from the producing oil(condensate)-gas ratio $r_p$, average surface gas gravity $\bar{\gamma}_g$, surface condensate gravity $\gamma_o$, and surface condensate molecular weight $M_o$,

$$\gamma_w = \frac{\bar{\gamma}_g + 816 \ r_p \ \gamma_o}{1 + 2.368\times 10^4 \ r_p \ (\gamma/M)_o} \tag{4-51}$$

with $r_p$ in $Sm^3/Sm^3$. Average surface gas gravity is given by

$$\bar{\gamma}_g = \frac{\sum_{i=1}^{N_{sp}} GOR_i \ \gamma_{gi}}{\sum_{i=1}^{N_{sp}} GOR_i} \tag{4-52}$$

Eq. (4-51) is presented graphically in Chart 22 of the *Fluid Properties Data Book*[33].

When $M_o$ is not available, the recommended correlation for estimating $M_o$ is given by Cragoe[34,35],

$$M_o = \frac{6084}{\gamma_{API} - 5.9} \tag{4-53}$$

This correlation gives reasonable values of $M_o$ for both surface condensates and stock-tank oils.

A typical problem is that all of the data required to calculate wellstream gas volumes and wellstream specific gravity are not available and must be estimated. In practice, we often have reported only the first stage separator GOR (relative to STO volume) and gas specific gravity, $R_{s1}$ and $\gamma_{g1}$, the stock-tank oil gravity $\gamma_o$, and the primary separator conditions $p_{sp1}$ and $T_{sp1}$.

The same approach as discussed in the section on oil PVT correlations can be used here (Eqs. (4-1) to (4-7)). The total producing oil-gas ratio is simply

$$r_p = r_s = 1/R_s = 1/(R_{s1}+R_{s+})$$

The wellstream gravity $\gamma_w$ is calculated using $r_p$, $\gamma_o$, $M_o$, and $\bar{\gamma}_g$ in Eq. (4-51).

### 4.5.5 Wet Gas and Dry Gas Volume Factors

Thus far $B_g$ has been defined assuming that the gas volume at p and T remains as a gas at standard conditions. For wet gases and gas condensates the surface gas will not contain all of the original gas mixture because surface condensate is produced after separation. For these mixtures the traditional definition of $B_g$ may still be used, but we refer to this quantity as a hypothetical *wet-gas volume factor* ($B_{gw}$) calculated from Eq. (4-38).

If the reservoir gas yields condensate at the surface, the *dry-gas volume factor* $B_{gd}$ is sometimes used (for example in modified black-oil simulators),

$$\begin{aligned} B_{gd} &= (\frac{p_{sc}}{T_{sc}})\frac{ZT}{p}(1+C_{og}\,r_s) \\ &= B_{gw}(1+C_{og}\,r_s) \end{aligned} \qquad (4\text{-}54)$$

with $r_s$ in $Sm^3/Sm^3$, $B_{gd}$ and $B_{gw}$ in $m^3/Sm^3$, T in K, p in bara; $C_{og}$ is a conversion from surface oil volume in $Sm^3$ to an "equivalent" surface gas in $Sm^3$,

$$\begin{aligned} C_{og} &= 379\,(\frac{scf}{lbmol}) \times 5.615\,(\frac{ft^3}{STB}) \times 62.4\frac{\gamma_{og}}{M_{og}}\,(\frac{lbmol}{ft^3}) \\ &= 133{,}000\frac{\gamma_{og}}{M_{og}}\,(\frac{scf}{STB}) \\ &= 2.368\times 10^4\frac{\gamma_{og}}{M_{og}}\,(\frac{Sm^3}{Sm^3}) \end{aligned} \qquad (4\text{-}55)$$

If condensate molecular weight $M_{og}$ is not measured then it can be estimated with the Cragoe correlation,

$$M_o = \frac{6084}{\gamma_{API} - 5.9} \qquad (4\text{-}56)$$

The term $(1+C_{og}r_s)^{-1}$ represents the mole fraction of reservoir gas that becomes dry surface gas after separation and usually ranges from 0.85 for rich gas condensates to 1.0 for dry gases.

An approximate correlation for estimating solution oil-gas ratio is (Whitson, 1994, unpublished)

$$\begin{aligned} r_s &= r_s^*(0.08 + 4\times10^{-7}\ p^{2.5}) \\ r_s^* &= 1.25\times10^{-6}\ R_s^*\ ;\ R_s^* = R_s \text{ at 345 bara (5000 psia)} \end{aligned} \qquad (4\text{-}57)$$

with $r_s$ and r in $Sm^3/Sm^3$, $R_s$ and R in $Sm^3/Sm^3$, and p in bara. R is the solution gas-oil ratio of a hypothetical reservoir oil in equilibrium with the reservoir gas at 5000 psia (345 bara). A bubblepoint correlation can be used to estimate R using the approximate relations

$$(\gamma_g)_{\text{reservoir oil}} \approx (\gamma_g)_{\text{resrevoir gas}}$$

$$(\gamma_{API})_{\text{reservoir oil}} \approx 90 - (\gamma_{API})_{\text{reservoir gas}}$$

The correlation given by Eq. 4-54 is shown in Figure 4-9. The correlation estimates reasonable magnitude and pressure dependence of $r_s$, but it is probably not more accurate than about 10 to 20%.

### 4.5.6 Total Formation Volume Factor

The total formation volume factor $B_t$ is defined as the volume of a two-phase, gas-oil mixture at elevated pressure and temperature, divided by the stock-tank oil volume resulting when the two-phase mixture is brought to surface conditions,

$$B_t = \frac{V_o + V_g}{(V_o)_{sc}} \qquad (4\text{-}58)$$

$B_t$ is used for calculating the oil in-place for gas-condensate reservoirs, where $V_t$=$V_g$ Assuming one reservoir $m^3$ of hydrocarbon pore volume, the initial condensate in place in $Sm^3$ is given by N=1/$B_t$, and the initial "dry" separator gas in place is $G_d$=N$R_p$. $R_p$ is the initial producing gas-oil ratio.

When reservoir pressure is greater than or equal to the dewpoint pressure, $B_t$=$V_g$/$(V_o)_{sc}$, and $B_t$ is given by

$$\begin{aligned} B_t &= B_{gd} R_p \\ &= \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}\left(R_p + 2.368\times10^4 \frac{\gamma_o}{M_o}\right) \end{aligned} \qquad (4\text{-}59)$$

with $R_p$ in $Sm^3/Sm^3$. Condensate molecular weight $M_o$ can be estimated from the Cragoe correlation,

$$M_o = \frac{6084}{\gamma_{API} - 5.9} \qquad (4\text{-}60)$$

### 4.5.7 Gas Viscosity

Viscosity of reservoir gases generally ranges from 0.01 to 0.03 cp at standard and reservoir conditions, reaching up to 0.1 cp for near-critical gas condensates. Gas viscosities are rarely measured because most laboratories do not have the required equipment.

The most common gas viscosity correlation is given by Lee, Gonzales, and Eakin[36]

$$\mu_g = A_0 \ \exp(A_1 \rho_g^{A_2})$$

$$A_0 = 10^{-4} \times \frac{(9.379 + 0.46555\gamma_g)T^{1.5}}{209.2 + 558.0\gamma_g + T} \tag{4-61}$$

$$A_1 = 3.448 + (986.4/T) + 0.29231\gamma_g$$

$$A_2 = 2.447 - 0.2224\, A_1$$

with $\rho_g$ in g/cm$^3$ and T in $^o$R. This correlation is used by most reservoir laboratories when reporting gas viscosities based on measured specific gravities. McCain[7] claims that the correlation is reliable within 2-4% for gases with $\gamma_g$<1, with errors approaching 20% for rich gas condensates with $\gamma_g$>1.5.

Gases at very high pressure or with significant amounts of nonhydrocarbons should use the Lucas viscosity correlation[37]. Another correlation frequently used is the Carr, Kobayashi, and Burrows correlation[38].

## 4.6 Water/Brine PVT Correlations

### 4.6.1 Introduction

The connate or "original" water found in petroleum reservoirs usually contains dissolved salts, consisting mainly of sodium chloride (NaCl), and solution gas consisting mainly of $CO_2$, methane and ethane. Initial water saturation can range from 5 to 50% of the pore volume in the net-pay intervals of a reservior where production is primarily oil and gas. Higher water saturations are found in non-net pay, in the aquifer, and where water has swept oil or gas during a waterflood or water influx.

From a reservoir depletion point of view, the *amount* of water connected with a reservoir is as important as the properties of the water, particularly in material balance calculations where the water expansion (compressibility times water volume) may contribute significantly to pressure support. From a production point of view, the mobility of water is important, requiring the determination of water saturations (i.e. relative permeability) and water viscosity. For surface processing calculations, the composition of water, the water content in the produced wellstream, and the conditions where water and hydrocarbons coexist must be defined.

The three most important aspects of water-hydrocarbon phase behavior are:

- Mutual solubilities of gas and water
- Volumetric behavior of reservoir brines
- Hydrate formation and treatment

This section presents PVT correlations for water-hydrocarbon systems. The standard PVT properties, solution gas-water ratio $R_{sw}$, isothermal water compressibility $c_w$, water formation volume factor $B_w$, water viscosity $\mu_w$, and water content in gas $r_{sw}$ are correlated in terms of pressure, temperature, and salinity using graphical charts and empirical equations. Correlations for water-hydrocarbon interfacial tension $\sigma_{wh}$ are also presented.

At high temperatures and pressures, some correlations and the existing water-property data base are not adequate. Equations of state have been used with reasonable success in predicting mutual solubilities and phase properties of hydrocarbon-water systems at temperatures up to 200°C and pressures greater than 700 bara,. The effect of salinity on gas-water phase behavior has also, to some extent, been treated by EOS methods.

### 4.6.2 Properties and Correlations

Like all reservoir fluids, the properties of formation waters depend on composition, temperature, and pressure. Reservoir water is seldom pure, and it usually contains dissolved gases and salts. Total dissolved solids (TDS) usually consist mainly of NaCl, ranging from 10,000 ppm to about 300,000 ppm. Sea water has a salinity of about 30,000 ppm. Table 4-1 gives the composition of several reservoir brines.

Water is limited by how much salt it can keep in solution. The limiting concentration for NaCl brine is given by,

$$C^*_{sw} = 262{,}180 \; + \; 72\,T \; + \; 1.06\,T^2 \qquad (4\text{-}62)$$

with T in °C and $C^*_{sw}$ in ppm. If reservoir temperature is known but a water sample cannot be obtained, this relation gives the limiting salinity of the reservoir brine. Usually the salinity of a brine is less than 80% of the value given by Eq. (4-62). Otherwise, the best estimate of brine salinity can be taken from a neighboring reservoir in the same geological formation.

Scale buildup in tubing and surface equipment is caused by the precipitation of salts in produced brine. Scale is usually caused by precipitation of calcium carbonate, calcium sulfate (e.g. gypsum), barium or strontium sulfates, and iron compounds. Temperature, pressure, total salinity and salt composition are the primary variables determining the severity of scaling. Note that Eq. (4-62) should not be used for the detection of conditions that result in scale buildup.

Dissolved gas in water is usually less than 30 scf/STB (about 0.4 mol percent) at normal reservoir conditions. The effect of salt and gas content on water properties can be important, and the following discussion gives methods to estimate fluid properties in terms of temperature, pressure, dissolved gas, and salinity. Methods for estimating the PVT properties of formation water are usually based on first estimating the properties of pure water at reservoir temperature and pressure, then correcting the pure-water properties for salinity and dissolved gas.

### 4.6.3 Salinity

The cations dissolved in formation waters usually include $Na^+$, $K^+$, $Ca^{++}$, $Mg^{++}$, and the anions include $Cl^-$, $SO_4^{--}$, $HCO_3^-$. Most formation waters contain primarily sodium chloride (NaCl). Suspended salts, entrained solids, and corrosion-causing bacteria may also be present in reservoir waters, but these constituents do not usually affect the PVT properties of formation waters. The geochemistry of formation waters can be useful in detecting foreign water encroachment, and in determining its source. Table 4-1 gives example compositions of reservoir brines.

Salinity defines the concentration of salts in a saline solution (brine), and it may be specified as one of several quantities: weight fraction ($w_s$), mole fraction ($x_s$), molality ($c_{sw}$), molarity ($c_{sv}$), parts per million by weight ($C_{sw}$), and parts per million by volume ($C_{sv}$). These quantities are formally defined in Table 4-2, where $m_s$ is the mass of salt in g, $m_w^o$ is the mass of pure water in g, $n_s$ is the moles of salt in gmol, $n_w^o$ is the moles of pure water in gmol, and $V_w$ is the volume of the brine mixture in $cm^3$.

Some common conversions for the various concentrations are

$$\begin{aligned} C_{sv} &= \rho_w C_{sw} \\ C_{sw} &= \frac{C_{sv}}{\rho_w} = 10^6 w_s \\ c_{sw} &= \frac{17.1}{10^6 C_{sw}^{-1} - 1} \\ C_{sw} &= \frac{10^6}{17.1 c_{sw}^{-1} + 1} \end{aligned} \qquad (4\text{-}63)$$

where the last two equations apply for NaCl brines. If brine density $\rho_w$ at standard conditions (1.0135 bara and 15.5°C) is not reported, it can be estimated from the Rowe-Chou density correlation{Rowe, 1970 #342} for NaCl,

$$\rho_w\ (p_{sc}, T_{sc}) = (1.0009 - 0.7114 w_s + 0.26055 w_s^2)^{-1} \qquad (4\text{-}64)$$

with $\rho_w$ in $g/cm^3$ and $w_s$ in weight fraction TDS. For many engineering applications $\rho_w$=1 $g/cm^3$ is assumed, and the mass of salt is considered negligible compared with the mass of pure water, resulting in the approximate relations:

$$\begin{aligned} c_{sv} &\approx c_{sw} = c_s \\ C_{sw} &\approx C_{sv} = C_s \\ c_s &\approx 17.1(10^{-6})C_s \end{aligned} \tag{4-65}$$

where the constant $17.1(10^{-6})$ applies for NaCl brines.

### 4.6.4 Gas Solubilities in Water/Brine

The solubility of natural gases in water is rather complicated to estimate from empirical correlations. However, the effect of gas solubility is usually minor except at high temperatures. At temperatures less than about 150°C and pressures less than 350 bara, solubility is usually less than 0.4 mol percent, or about 5.5 $Sm^3/Sm^3$. According to Dodson and Standing's results[40], this amount of dissolved gas causes an increase of about 25 percent in water compressibility, e.g. from $5.5(10^{-5})$ to $7.0(10^{-5})$ $bar^{-1}$. Experimental gas solubilities for $C_1$-$C_4$, non-hydrocarbons, natural gas, and a few binaries and ternaries are available in the literature.

At reservoir conditions the solubility of methane in water and the effect of salinity are the most important variables affecting water properties. The following empirical equation gives a reasonable fit of the Culbertson and McKetta solubility data[41] for methane in pure water at conditions $38<T<175$°C and $0<p<700$ bara,

$$x_{C_1} = 10^{-3} \left[ \sum_{i=0}^{3} \left( \sum_{j=0}^{3} A_{ij} T^j \right) p^i \right] \tag{4-66}$$

where

$A_{00}$ = 0.299E+00 $A_{10}$ = 2.283E-03
$A_{01}$ = -1.273E-03 $A_{11}$ = -1.870E-05
$A_{02}$ = 0.000E+00 $A_{12}$ = 7.494E-08
$A_{03}$ = 0.000E+00 $A_{13}$ = -7.881E-11

$A_{20}$ = -2.850E-07 $A_{30}$ = 1.181E-11
$A_{21}$ = 2.720E-09 $A_{31}$ = -1.082E-13
$A_{22}$ = -1.123E-11 $A_{32}$ = 4.275E-16
$A_{23}$ = 1.361E-14 $A_{33}$ = -4.846E-19

with T in °F and p in psia. Gas solubility expressed as a solution gas-water ratio $R_{sw}$ at standard conditions is given by

$$R_{sw} = 1313 \frac{x_g}{1 - x_g} \approx 1313\, x_g \tag{4-67}$$

with $R_{sw}$ in $Sm^3/Sm^3$; replacing the constant 1313 with 7370 yields $R_{sw}$ in scf/STB.

A standard two-phase flash calculation using a cubic EOS gives surprisingly accurate prediction of gas solubilities, as discussed later in this chapter. This approach is the recommended procedure for estimating gas solubilities of hydrocarbon-water/brine mixtures at high pressures and temperatures.

### 4.6.5 Salinity Correction for Solubilities

Setchenow[42] (sometimes written Secenov) gives the following relation for correcting the hydrocarbon solubility in pure water for salt content,

$$k_s = \lim_{c_s \to 0} \left[ c_s^{-1} \log \frac{(\phi_i^\infty)_w}{(\phi_i^\infty)_w^o} \right] \qquad (4\text{-}68)$$

where $k_s$ is the Setchenow constant and $c_s$ is salt concentration; $(\varphi)_w$ and $(\varphi)^o_w$ are the fugacity coefficients of component i at infinite dilution in the salt solution and in pure water, respectively. Both molality and molarity have been used in the literature for defining Setchenow constants, though molality ($c_{sw}$) is now considered the preferred concentration, where the Setchenow constant has the unit molality$^{-1}$ (i.e., kg/gmol).

The ratio of infinite-dilution fugacity coefficients is traditionally assumed to give an accurate estimate of the ratio of solubilities, yielding the relation

$$\frac{R_{sw}}{R_{sw}^o} \approx \frac{x_g}{x_g^o} = 10^{-k_s c_s} \approx 10^{-17.1(10^{-6}) k_s C_s} \qquad (4\text{-}69)$$

where $R_{sw}^o$ is the solubility of gas in pure water and $R_{sw}$ is the solubility of gas in brine. For $k_s>0$ the gas solubility is less in brines than in pure water, a fact which has led to the use of "salting-out coefficient" for $k_s$.

The Setchenow constant is more or less independent of pressure, though it is a strong function of temperature. Cramer gives a detailed treatment of Setchenow (and Henry's) constants for the $C_1$-NaCl system using data at temperatures up to 300°C and pressures up to 135 bara. Søreide and Whitson[43] give a best-fit relation for the Cramer correlation[44],

$$\begin{aligned} (k_s)_{C_1\text{-NaCl}} &= 0.1813 - 7.692(10^{-4})T \\ &\quad + 2.6614(10^{-6})T^2 - 2.612(10^{-9})T^3 \end{aligned} \qquad (4\text{-}70)$$

with $k_s$ in molality$^{-1}$ and T in °F. Using relations suggested by Pawlikowski and Prausnitz[42] relating $k_s$ of methane to $k_s$ of other hydrocarbons, Søreide and Whitson propose the following relation for hydrocarbon $k_s$,

$$k_{si} = (k_s)_{C_1\text{-NaCl}} + 0.000445(T_{bi} - 111.6) \qquad (4\text{-}71)$$

with $k_s$ in molality$^{-1}$ and the normal boiling point $T_{bi}$ in K.

Clever and Holland[45] give salting-out correlations for $C_1$-NaCl and $CO_2$-NaCl systems. The correlation for $CO_2$-NaCl is

$$\begin{aligned}(k_s)_{CO_2\text{-NaCl}} &= 0.257555 - 0.157492(10^{-3})T \\ &\quad - 0.253024(10^{-5})T^2 + 0.438362(10^{-8})T^3\end{aligned} \tag{4-72}$$

with T in K and $k_s$ in molality$^{-1}$. The temperature range for Eq. (4-72) is 4<T<350°C. The Setchenow coefficient varies somewhat with pressure for the $CO_2$-NaCl system, thereby making Eq. (4-72) less accurate than hydrocarbon-NaCl correlations.

### 4.6.6 Equilibrium Conditions in Oil/Gas-Water Systems

All phases - oil, gas, and water - in a reservoir are initially in thermodynamic equilibrium. This implies that the water phase contains finite quantities of *all* hydrocarbon and nonhydrocarbon components found in the hydrocarbon phases, and that the hydrocarbon phases contain a finite quantity of water. The amount of lighter compounds ($C_1$, $C_2$, $N_2$, $CO_2$, and $H_2S$) in the water phase can be significant, depending mainly on the amount of each component in the hydrocarbon phase(s). The amount of $C_{3+}$ hydrocarbons found in water is usually small and can be neglected.

The K-value representing the ratio of the mole fraction of component i in the hydrocarbon phase to the mole fraction of component i in the water phase, $K_i=z_{i,HC}/x_{i,AQ}$, is approximately constant at a given pressure and temperature, independent of overall hydrocarbon composition and whether the hydrocarbon is single phase or two-phase. For example, the amount of methane dissolved in water for a methane-rich natural gas will be higher than the amount of methane dissolved in water for an oil (above its bubblepoint). Furthermore, the amount of methane dissolved in water for a gas-oil system with overall methane content of 40 mol-% will probably be about the same as for a single-phase oil with 40 mol-% methane.

An oil that is undersaturated (*with respect to gas*) is still in equilibrium with the water phase. When pressure is lowered, a new equilibrium state is reached between the gas-undersaturated oil and water. The result is that some of the methane will move from the water to the oil (without forming free gas). That is, the solution gas-water ratio decreases. At some lower pressure the oil will reach its bubblepoint (with respect to gas), and further reduction in pressure will yield two sources of free gas: (1) gas coming out of solution from the oil, and (2) gas coming out of solution from the water.

Therefore, for an undersaturated oil reservoir, the solution gas-water ratio of reservoir brine will continuously decrease from the initial reservoir pressure down to the reservoir oil's bubblepoint pressure, and further at lower pressures. Correspondingly, the reservoir oil solution GOR will *increase* (albeit slightly) from initial pressure to the bubblepoint pressure, thereafter decreasing below the bubblepoint. An EOS can be used to quantify the changing solution gas-water and gas-oil ratios in this situation.

### 4.6.7 Water/Brine FVF and Compressibility

The FVF of reservoir water $B_w$ depends on pressure, temperature, salinity, and dissolved gas. Contrary to saturated oil volumetric behavior, the liquid volume of a gas-saturated water increases with decreasing pressure. That is, the expansion due to isothermal compressibility is larger than the shrinkage due to gas coming out of solution.

The pressure dependence of $B_w$ given by Dodson and Standing[40] for gas-saturated water/brine will apply to all gas reservoirs and oil reservoirs with appreciable solution gas. Even if the oil is undersaturated, as discussed earlier, the solution gas-water ratio will decrease continuously from the initial pressure to the oil bubblepoint pressure and further thereafter.

The formation volume factor $B_w^o$ of brine at atmospheric pressure, reservoir temperature, and without dissolved gas is given by

$$B_w^o = \frac{\rho_w(p_{sc}, T_{sc})}{\rho_w^o(p_{sc}, T)} = \frac{\bar{v}_w^o(p_{sc}, T)}{\bar{v}_w(p_{sc}, T_{sc})} \tag{4-73}$$

Long and Chierici[46] give experimental data and correlations for the density of pure water and NaCl brine solutions, though the proposed correlations extrapolate poorly at temperatures greater than about 120°C.

The following correlation is given by Rowe and Chou[39] for water and NaCl brine specific volume at zero pressure (also applicable at atmospheric pressure),

$$\begin{aligned}
\bar{v}_w^o(p_{sc}, T) &= \frac{1}{\rho_w^o(p_{sc}, T)} = A_0 + A_1 w_s + A_2 w_s^2 \\
A_0 &= 5.916365 - 0.01035794T + 0.9270048(10^{-5})T^2 \\
&\quad - 1127.522T^{-1} + 100674.1T^{-2} \\
A_1 &= -2.5166 + 0.0111766T - 0.170552(10^{-4})T^2 \\
A_2 &= 2.84851 - 0.0154305T + 0.223982(10^{-4})T^2
\end{aligned} \tag{4-74}$$

with  in cm$^3$/g, T in K, and $w_s$ as weight fraction of NaCl. The effect of pressure on FVF can be calculated using the definition of water compressibility,

$$c_w^* = -\frac{1}{B_w}\left(\frac{\partial B_w}{\partial p}\right)_{C_s, T} \tag{4-75}$$

which when integrated gives

$$\ln\frac{B_w^*(p, T)}{B_w^o(p_{sc}, T)} = -\int_0^p c_w^*(p, T)\,dp \tag{4-76}$$

Using the compressibility data reported by Rowe and Chou covering the conditions $20<T<175$°C, $10<p<310$ bara, and $0<w_s<0.3$, a general correlation for the compressibility of a brine (*without solution gas*), $c_w^*$, is

$$\begin{aligned} &c_w^*(p,T) = (A_0 + A_1 p)^{-1} \\ &A_0 = 10^6[0.314 + 0.58 w_s + 1.9(10^{-4})T \\ &\qquad -1.45(10^{-6})T^2] \\ &A_1 = 8 + 50 w_s - 0.125 w_s T \end{aligned} \tag{4-77}$$

with $c^*_w$ in psi$^{-1}$, p in psia, T in °F, and $w_s$ in weight fraction of NaCl. Solving Eq. (4-76) for the FVF of a brine without solution gas, $B^*_w$ gives

$$B_w^*(p,T) = B_w^o(p_{sc},T) \times \left(1 + \frac{A_1}{A_0}\,p\right)^{(-1/A_1)} \tag{4-78}$$

where $A_0$ and $A_1$ are given in Eq. (4-77). Eq. (4-78) results in water and brine densities that are within 0.5 percent of values given by the highly accurate correlation of Rogers and Pitzer[47] for 15<T<200°C, 0<p<1,000 bara, and $0<C_s<300{,}000$ ppm. For the same range of conditions, Eq. (4-77) calculates isothermal compressibilities within about five percent of the values given by Rogers and Pitzer.

Using Dodson and Standing's data for pure water saturated with a natural gas, an *approximate* correction for dissolved gas on water/brine FVF at saturated conditions is given by

$$B_w(p,T,R_{sw}) = B_w^*(p,T) \times (1 + 0.0001\,R_{sw}^{1.5}) \tag{4-79}$$

with $R_{sw}$ in scf/STB. This relation fits the Dodson-Standing data at 150, 200, and 250°F, but overpredicts the effect of dissolved gas at 100°F.

Dodson and Standing also give a correction for the effect of dissolved gas on water/brine compressibility,

$$c_w(p,T,R_{sw}) = c_w^*(p,T) \times (1 + 0.00877\,R_{sw}) \tag{4-80}$$

with $R_{sw}$ in scf/STB. This relation is only valid for undersaturated oil-water systems above the oil bubblepoint pressure.

### 4.6.8 Water/Brine Viscosity

The viscosity of pure water and NaCl brines are functions of temperature and salinity, and can be estimated from the following equations presented by Kestin et al.[48] who report an accuracy of ±0.5% in the range 20<T<150°C, 0<p<350 bara, and 0<$C_{sw}$<300,000 ppm (0<$c_{sw}$<5 molality),

$$
\begin{aligned}
&\mu_w = (1 + A_0 p)\mu_w^* \\
&\log \frac{\mu_w^*}{\mu_w^o} = A_1 + A_2 \log \frac{\mu_w^o}{\mu_{w\,20}^o} \\
&A_0 = 10^{-3}[0.8 + 0.01(T - 90)\exp(-0.25 c_{sw})] \\
&A_1 = \sum_{i=1}^{3} a_{1i} c_{sw}^i \qquad\qquad (4\text{-}81) \\
&A_2 = \sum_{i=1}^{3} a_{2i} c_{sw}^i \\
&\log \frac{\mu_w^o}{\mu_w 20^o} = \sum_{i=1}^{4} a_{3i} \frac{(20 - T)^i}{96 + T} \\
&\mu_w 20^o = 1.002 \text{ cp}
\end{aligned}
$$

where

$a_{11}$ = 3.324E-2 $a_{21}$ = -3.96E-2 $a_{31}$ = 1.2378
$a_{12}$ = 3.624E-3 $a_{22}$ = 1.02E-2 $a_{32}$ = -1.303E-3
$a_{13}$ = -1.879E-4 $a_{23}$ = -7.02E-4 $a_{33}$ = 3.060E-6
$a_{34}$ = 2.550E-8

with $\mu$ in cp, T in °C, and p in MPa. The pressure correction $A_0$ given by Kestin et al. contains 13 constants and does not extrapolate well at high temperatures. The pressure correction for $A_0$ given above is a more well-behaved equation, with only small deviations from the original Kestin et al. correlation (at low temperatures).

The effect of dissolved gas on water viscosity has not been reported. Intuitively, one might suspect that water viscosity decreases with increasing gas solubility, though Collins suggests that dissolved gas may increase brine viscosity. Systems saturated with $CO_2$ do show an increase in viscosity with increasing gas solubility.

### 4.6.9 Solubility of Water in Natural Gas

The solubility of pure water in methane is given by McKetta and Wehe[41] who give charts for correcting pure water solubilities for salinity and gas gravity (based mainly on the results of Dodson and Standing). A best-fit equation for these charts is

$$\begin{aligned}
y_w &= y_w^o\, A_g\, A_s \\
\ln y_w^o &= \frac{0.05227\,p + 142.3 \ln p - 9625}{T + 460} - 1.117 \ln p + 16.44 \\
A_g &= 1 + \frac{\gamma_g - 0.55}{1.55(10^4)\,\gamma_g\, T^{-1.446} - 1.83(10^4)\,T^{-1.288}} \\
A_s &= 1 - 3.92(10^{-9})\, C_s^{1.44}
\end{aligned} \tag{4-82}$$

with T in °F, p in psia, and $C_s$ in ppm or mg/L. Eq. (4-82) yields an absolute average deviation of 2.5 percent for $y_w^o$, with a maximum error less than 10 percent for 35<T<240°C and 15<p<700 bara. Mole fraction of water in gas $y_w$ can be converted to a water-gas ratio $r_{sw}$ using the relation

$$r_{sw} = 7.58\times10^{-4} \frac{y_w}{1 - y_w} \approx 7.58\times10^{-4}\, y_w \tag{4-83}$$

with $r_{sw}$ in $Sm^3/Sm^3$. Replacing the constant $7.58{\cdot}10^{-4}$ with 135 yields $r_{sw}$ in STB/MMscf, and replacing with 47,300 yields $r_{sw}$ in lb/MMscf.

The correction term for salinity $A_s$ proposed by Dodson and Standing is based on limited results for one low-salinity brine. The salinity correction given by Katz, et al.[49] (given in Eq. (4-82)) is based on the lowering of vapor pressure for brine solutions at 100°C, where the assumption is made that

$$\frac{y_w}{y_w^o} \approx \frac{p_{vw}(100^\circ C, C_s)}{p_{vw}^o(100^\circ C)} \tag{4-84}$$

where $p_{vw}$ is the brine vapor pressure and $p_{vw}^o$ is the pure-water vapor pressure, both measured at 100°C. Very little data is available to confirm these two salinity corrections. However, EOS calculations indicate that the Katz et al. correlation is probably valid up to a molality of about 3; at larger molalities the EOS-calculated ratio $y_w / y_w^o$ is less than predicted by the Katz et al. correlation.

Finally, water that is dissolved in reservoir gas and oil mixtures will not contain salts (i.e. it is fresh water), a fact that can help in identifying the origin of produced water.

### 4.6.10 Water/Brine-Hydrocarbon Interfacial Tension

The interfacial tension of water-hydrocarbon systems $\sigma_{wh}$ varies from about 72 mN/m (72 dynes/cm) for water/brine-gas systems at atmospheric conditions to 20-30 mN/m for water/brine-STO systems at atmospheric conditions. The variation in $\sigma_{wh}$ is nearly linear with the density difference between water and the hydrocarbon phase $\Delta\rho_{wh}$ (i.e., $\Delta\rho_{wo}$ or $\Delta\rho_{wg}$), where $\sigma_{wh}$=72 mN/m at $\Delta\rho_{wh}=\Delta\rho_{wg}=1$ g/cm$^3$. This can be expressed in equation form as

$$\sigma_{\mathrm{wh}} = \sigma^{\mathrm{o}} + (72 - \sigma^{\mathrm{o}})\Delta\rho_{\mathrm{wh}} \qquad (4\text{-}85)$$

where $\sigma^{o}$ is the intercept at $\Delta\rho_{wh}$=0.

Ramey[50], in an unpublished SPE paper, proposes a correlation for $\sigma_{wh}$ based on the Macleod parameter $\sigma^{1/4}/\Delta\rho$. This parameter was plotted versus $\Delta\rho$ using data for brines with stock-tank oil, saturated and undersaturated reservoir oils, and natural gases. Ramey's graphical correlation is represented surprisingly well with Eq. (4-85), where $\sigma^{o}$=15; a near-exact fit of his correlation is given by

$$\sigma_{\mathrm{wg}} = 20 + 36\,\Delta\rho_{\mathrm{wh}} \qquad (4\text{-}86)$$

Data presented by Ramey which do not lie on his general correlation are represented accurately by Eq. (4-85) with $\sigma^{o}$ ranging from 5 to 30.

Firoozabadi and Ramey[51] consider the interfacial tension of water and hydrocarbons using data for distilled water and pure hydrocarbons. They arrive at a similar graphical relation to the original Ramey correlation, with the addition of reduced temperature as a correlating parameter. Their correlation does not, unfortunately, predict water/brine-oil IFTs with more accuracy than the original Ramey correlation (or Eq. (4-85)). Water-gas IFTs reported by various authors show considerable scatter, and it would seem that any correlation will only give approximate IFT values for such systems until consistent data becomes available.

Mutual solubility effects of gas dissolved in water and water dissolved in gas may affect interfacial tensions, perhaps explaining some of the difference in methane-brine and methane-water IFTs reported in the literature. Otherwise, the seemingly erratic behavior of some water/brine-oil IFT data may be explained by aromatic compounds and asphaltenes. Also, crude oil samples exposed to atmospheric conditions for longer periods of time may experience oxidation that can affect IFT measurements.

### 4.6.11 Equation-of-State Predictions

Mutual solubilities and volumetric properties of water-hydrocarbon systems can be predicted with reasonable accuracy using one of several modifications to existing cubic equations of state. Other types of equations of state also have been applied to these systems, but without a clearly superior predictive capability. Although cubic EOSs are not widely used for reservoir water-hydrocarbon systems, it is expected that this approach will eventually replace the empirical correlations presently being used.

To improve vapor pressure predictions of water (and solubilities of water in the non-aqueous phase), Peng and Robinson[52] propose a modified correction term $\alpha$ (applied to the EOS constant a) for pure water in the temperature range $0.44<T_r<0.72$ ($15<T<200$°C). The recommended Søreide-Whitson relation[43] for $\alpha_{H2O}$ of pure water (or NaCl brine) to be used with the Peng-Robinson EOS is

$$\begin{aligned}\alpha^{0.5}_{H_2O} = 1 + 0.453\,&\left[1 - T_{r\,H_2O}\left(1 - 0.0103 c^{1.1}_{sw}\right)\right.\\ &\left.+ 0.0034\left(T^{-3}_{r\,H_2O} - 1\right)\right]\end{aligned} \qquad (4\text{-}87)$$

With this $\alpha$ term for water/brine, the PR EOS will predict the vapor pressure of pure water within 0.2 percent of steam-table values for the range $0.44<T_{rH2O}<1$ (i.e. T>15°C); it also can be used to predict vapor pressure of NaCl solutions with the same accuracy.

With a correction for salinity in the $\alpha$ term it is expected that the predicted solubilities of water in nonaqueous phases will be fairly accurate.

The most important modification of existing cubic EOSs for water-hydrocarbon systems is the introduction of alternative mixing rules for EOS constant A, where different binary interaction coefficients $k_{ij}$ are used for the aqueous and non-aqueous (hydrocarbon) phases.

Peng and Robinson propose a simple EOS modification for hydrocarbon-water systems; namely, two sets of $k_{ij}$ are defined, $k_{ij,HC}$ for the hydrocarbon phase(s) and $k_{ij,AQ}$ for the aqueous phase. The EOS constant A is therefore calculated separately for the aqueous and hydrocarbon phases,

$$\begin{aligned}A_{HC} &= \sum_{i=1}^{N}\sum_{j=1}^{N} y_{i,HC}\, y_{j,HC}\; A_i A_j\; (1 - k_{ij,HC})\\ A_{AQ} &= \sum_{i=1}^{N}\sum_{j=1}^{N} x_{i,AQ}\, x_{j,AQ}\; A_i A_j\; (1 - k_{ij,AQ})\end{aligned} \qquad (4\text{-}88)$$

where $y_{i,HC}$ is the hydrocarbon composition (gas or oil) and $x_{i,AQ}$ is the composition of the water phase. Using two sets of $k_{ij}$ has been successfully applied to correlate mutual solubilities of hydrocarbon-water and nonhydrocarbon-water binary systems.

Table 4-3 gives recommended $k_{ij}$ relations for both aqueous and non-aqueous phases for the Peng-Robinson EOS, where these interaction coefficients must be used with the general $\alpha_{H2O}$ relation (Eq. (4-87)). The $CO_2$-water/brine correlation gives best results at pressures less than about 350 bara, as data in this region have been given more weight when developing the correlation.

Considerable data on solubilities of hydrocarbon and nonhydrocarbon gases in brine solutions were used in making the salinity corrections for aqueous phases $k_{ij}$. Similar data were not available for solubilities of water in the nonaqueous phase for mixtures containing brines. Until more data become available it will be necessary to assume that the effect of salinity is adequately treated by the modified $\alpha_{H2O}$ term (Eq. (4-87)).

Simultaneous application of both aqueous and non-aqueous phase interaction coefficients requires modification of the standard EOS implementation (which uses a single set of $k_{ij}$).

A standard implementation of the PR EOS can still be used with the BIPs given in Table 4-3. If only gas solubility in the water phase is needed then accurate gas solubilities are predicted using the aqueous phase $k_{ij,AQ}$ for both phases. However, the calculated water content in the hydrocarbon phase will not be accurate. Likewise, if only water solubility in the hydrocarbon phase is needed then the hydrocarbon phase $k_{ij,HC}$ can be used for both phases; the calculated HC content in the aqueous phase will not, however, be accurate.

Several non-cubic equations of state have been proposed for water-hydrocarbon systems, including conventional activity coefficient models that are limited to relatively low pressures, and more general electrolyte EOS models. However, these models do not appear to be better than the simpler modifications of cubic EOSs.

### 4.6.12 Converting EOS Results to $B_w$, $R_{sw}$, and $r_{sw}$

Physical properties of gas-water systems used in petroleum engineering can be derived from equation of state (EOS) calculations as shown below. The EOS calculations are based on the Peng-Robinson EOS[52] with interaction coefficients proposed by Søreide and Whitson.[43] Volumetric properties are also calculated with the EOS using volume translation, where shift parameters are determined to ensure accurate volumetric properties of water-free gas and gas-free water (using the MATCh command in PVTx[53]).

A constant volume depletion (CVD) experiment is simulated with PVTx using as initial feed the reported water-free gas composition (e.g. summing to 100). A specified amount of brine component (e.g. 100) is also included in the feed. The amount of brine component added determines the initial water saturation when the overall feed (normalized automatically by PVTx) is flashed at initial reservoir conditions. For the Washita Creek reservoir, adding 49.0 moles of brine to 100 moles of water-free gas resulted in an initial water saturation of 10%.

Note that the PSAT=OFF option in PVTx must be used when simulating the CVD experiment for this type of analysis. To make water-hydrocarbon calculations with PVTx, several special commands are used:

1. The PROP command defines the properties of the brine component.

2. The interaction parameters for the non-aqueous phase (BIPS) and the aqueous phase (BIPS WATER) are specified.

3. The MATCh command is needed to define the volume translation parameter of the brine component.

4. The KCOR WATER command is used to initialize K-values.

### BIPWAT (Lotus 1-2-3) Spreadsheet

All input parameters required for PVTx can be generated using the Lotus 1-2-3 spreadsheet BIPWAT.WK3 (Søreide and Whitson correlations). Note that for the Washita Creek study, the volume translation coefficients of both methane and $CO_2$ were modified slightly to fit water-free gas Z-factors calculated using the Standing-Katz chart[3] (Hall-Yarborough EOS correlation[25]).

The spreadsheet also calculates brine viscosity as a function of pressure and temperature (the effect of non-aqueous component solubilities on viscosity is not included). Results can be used to calculate the viscosibility

$$C_{vw} = (d\mu_w/dp)\mu$$

where $\mu_w^o$ is the water viscosity at the reference pressure (e.g. initial reservoir pressure).

### Gas-Water Physical Properties

EOS calculations yield the following basic results needed for calculation of gas-water physical properties:

1. Reservoir gas Z-factor $Z_g$.
2. Reservoir water density $\rho_w$.
3. Compositions of reservoir gas ($y_j$) and reservoir water ($x_j$).
4. Reservoir water saturation ($S_w$); variable "vro" in PVTx.

Component molecular weights are also used, as is the component brine density at standard conditions, $\rho_{brine}$.

The Lotus 1-2-3 spreadsheet BIPWAT.WK3 results and PVTx input data set for example Visund gas-water and oil-water systems are included in section 5.8.

Some of the properties calculated with equations below are also reported by PVTx (e.g. reservoir water molecular weight $M_w$ and reservoir gas specific gravity $\gamma_g$). The calculated values should be the same as output by PVTx; use as a check.

Solution Water-Gas Ratio ($r_{sw}$)[a]

$$R_{vw} = r_{sw} = 0.0423(\frac{M_{brine}}{\rho_{brine}})(\frac{y_{brine}}{1 - y_{brine}}) \qquad (4\text{-}89)$$

---

[a] Water in solution in the reservoir gas is actually fresh water. Because the EOS does not "know" that the water partitioning into gas is salt-free, the correct equation for $r_{sw}$ (based on pure water) can not be used,

Solution Gas-Water Ratio ($R_{sw}$)

$$R_{sw} = 23.66 \left(\frac{\rho_{brine}}{M_{brine}}\right) \left(\frac{1 - x_{brine}}{x_{brine}}\right) \tag{4-90}$$

Reservoir Water FVF ($B_w$)

$$B_w = \frac{(\rho_{brine})_{sc} + 1.22\, \gamma_{gds}\, R_{sw}}{\rho_w} \tag{4-91}$$

Reservoir Gas Specific Gravity ($\gamma_g$)

$$\gamma_g = \frac{\sum\limits_{j=1}^{n} y_j M_j}{28.97 \sum\limits_{i=j}^{n} y_j} \tag{4-92}$$

Reservoir Gas Density ($\rho_g$)

$$\rho_g = \frac{28.97\, p\, \gamma_g}{Z_g RT} \tag{4-93}$$

Reservoir Gas FVF ($B_g$)

$$B_g = 0.00351 \frac{Z_g T}{p} \tag{4-94}$$

Free Dry (Water-Free) Gas Specific Gravity ($\gamma_{gd}$)

$$\gamma_{gd} = \frac{\sum\limits_{j \neq brine} y_j M_j}{28.97\,(1 - y_{brine})} \tag{4-95}$$

Solution Dry (Water-Free) Gas Specific Gravity ($\gamma_{gds}$)

$$\gamma_{gds} = \frac{\sum\limits_{j \neq brine} x_j M_j}{28.97\,(1 - x_{brine})} \tag{4-96}$$

where units are p in bara, T in K, $\rho$ in kg/m$^3$, $r_{sw}$ and $R_{sw}$ in Sm$^3$/Sm$^3$, and FVFs $B_g$ and $B_w$ in m$^3$/Sm$^3$.

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**Table 4-1**

| Component | Sea Water (ppm) | Dodson-Standing (ppm) | | Arun Field (mg/L) | Visund Amundsen/ Statfjord (mg/L) | Kansas[*] Wilcox (mg/L) | Kansas[**] Wilcox (mg/L) |
|---|---|---|---|---|---|---|---|
| | | Brine A | Brine B | | | | |
| Sodium (Na) | 10,560 | 3,160 | 12,100 | 5,212 | 11,300 | 10,800 | 142,500 |
| Calcium (Ca) | 400 | 58 | 520 | 80 | 650 | 790 | 14,400 |
| Magnesium (Mg) | 1,270 | 40 | 380 | 5 | 90 | 5,560 | 68,500 |
| Sulfate ($SO_4$) | 2,650 | 0 | 5 | 262 | 0 | 80 | 300 |
| Chloride (Cl) | 18,980 | 4,680 | 20,000 | 7,090 | 19,200 | 10,870 | 142,600 |
| Bicarbonate ($HCO_3$) | 140 | 696 | 980 | 1,536 | 800 | 20 | 530 |
| Iodide (I) | 0 | 0 | 130 | 0 | 0 | 0 | 3 |
| Bromide (Br) | 65 | 0 | 0 | 0 | 0 | 80 | 350 |
| Others | 515 | 0 | 0 | 0 | 1,104[***] | 0 | 0 |
| Total | 34,580 | 8,630 | 34,110 | 14,190 | 33,144 | 28,200 | 369,180 |
| Specific Gravity | 1.0243 @ 20°C | (1.006) @ 60°F | (1.024) @ 60°F | 1.014 @ 60°F | 1.0235 @ 20°C | 1.015 @ 60°F | 1.140 @ 60°F |

[*] Minimum salt-containing composition reported for the field/formation.
[**] Maximum salt-containing composition reported for the field/formation.
[***] Potasium (K): 600; Stronium (Sr): 230; Barium (Ba): 270; Iron (Fe): 4 mg/L.
Specific gravities in parentheses are estimated using Eq. 4-61.

## Table 4-2

| Quantity | Symbol | Unit | Definition |
|---|---|---|---|
| Weight Fraction | $w_s$ | g/g | $m_s/(m_s+m)$ |
| Mole Fraction | $x_s$ | gmol/gmol | $n_s/(n_s+n)$ |
| Molality | $c_{sw}$ | gmol/kg | $10^3 n_s/m$ |
| Molarity | $c_{sv}$ | gmol/L | $10^3 n_s/V_w$ |
| PPM (weight basis) | $C_{sw}$ | mg/kg | $10^6 m_s/(m_s+m)$ |
| PPM (volume basis) | $C_{sv}$ | mg/L | $10^6 m_s/V_w$ |

$n_s$ = Moles salt
$m_s$ = Mass salt
n = Moles pure water
m = Mass pure water
$V_w$ = Volume brine solution

## Table 4-3

AQUEOUS PHASE

Hydrocarbons (i=HC ; j=water/brine):

$$k_{ij,AQ} = (1 + a_0 c_{sw}) A_0 + (1 + a_1 c_{sw}) A_1 T_{ri} + (1 + a_2 c_{sw}) A_2 T_{ri}^2$$

$$a_0 = 4.7863(10^{-13})\,\omega_i^4$$
$$a_1 = 0.01438$$
$$a_2 = 0.0021547$$

$$A_0 = 1.112 - 1.7369\,\omega_i^{-0.1}$$
$$A_1 = 1.1001 + 0.836\,\omega_i$$
$$A_2 = -0.15742 - 1.0988\,\omega_i$$

Nitrogen (i=$N_2$ ; j=water/brine):

$$k_{ij,AQ} = -1.70235(1 + 0.025587\,c_{sw}^{0.75}) + 0.44338(1 + 0.08126\,c_{sw}^{0.75})\,T_{ri}$$

Carbon Dioxide (i=$CO_2$ ; j=water/brine):

$$k_{ij,AQ} = -0.31092(1 + 0.15587\,c_{sw}^{0.75}) + 0.2358(1 + 0.17837\,c_{sw}^{0.98})\,T_{ri} - 21.2566\exp(-6.7222\,T_r - c_{sw})$$

Hydrogen Sulfide (i=$H_2S$ ; j=water/brine):

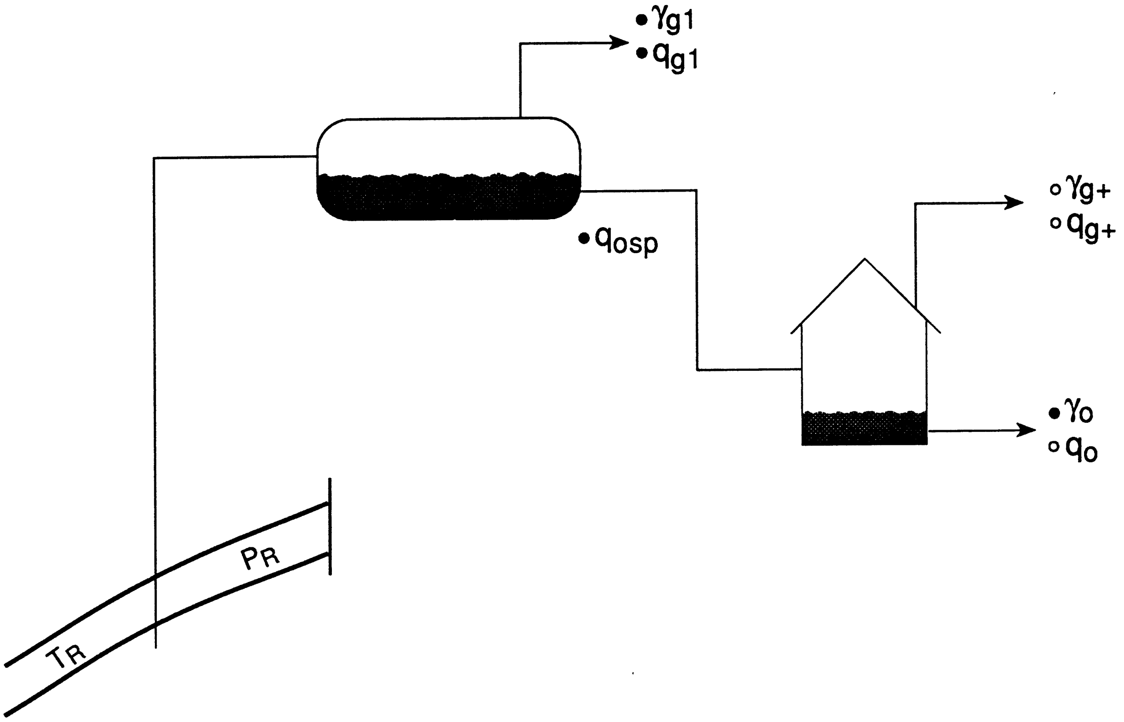
$$k_{ij,AQ} = -0.20441 + 0.23426\,T_{ri}$$

The acentric factors used in developing HC-water BIPs are:

| | |
|---|---|
| $C_1$ | 0.0108 |
| $C_2$ | 0.0998 |
| $C_3$ | 0.1517 |
| $C_4$ | 0.1931 |

| NON-AQUEOUS PHASE | |
|---|---|
| i | $k_{ij,HC}$ (j=water) |
| $C_1$ | 0.4850 |
| $C_2$ | 0.4920 |
| $C_3$ | 0.5525 |
| $C_4$ | 0.5091 |
| $C_{5+}$ | 0.5000 |
| $N_2$ | 0.4778 |
| $CO_2$ | 0.1896 |
| $H_2S$ | 0.19031-0.0.05965$T_{ri}$ |

**Table 4-4**



| ●Measured | ○Calculated |
|---|---|
| $\gamma_{g1}$ | $\gamma_{g+}$ |
| $q_{g1}$ | $R_{s+}$ |
| $q_{osp}$ | $\bar{\gamma}_g$ |
| $\gamma_o$ | $R_s$ |
| $(B_{osp}, q_o)$ | $(B_{osp}, q_o)$ |

## General Relationships

$q_o = q_{osp}/B_{osp}$

$R_{sp1} = q_{g1}/q_{osp}$

$R_{s1} = q_{g1}/q_o = R_{sp1} B_{osp}$

$R_{s+} = q_{g+}/q_o$

**Figure 4-1**

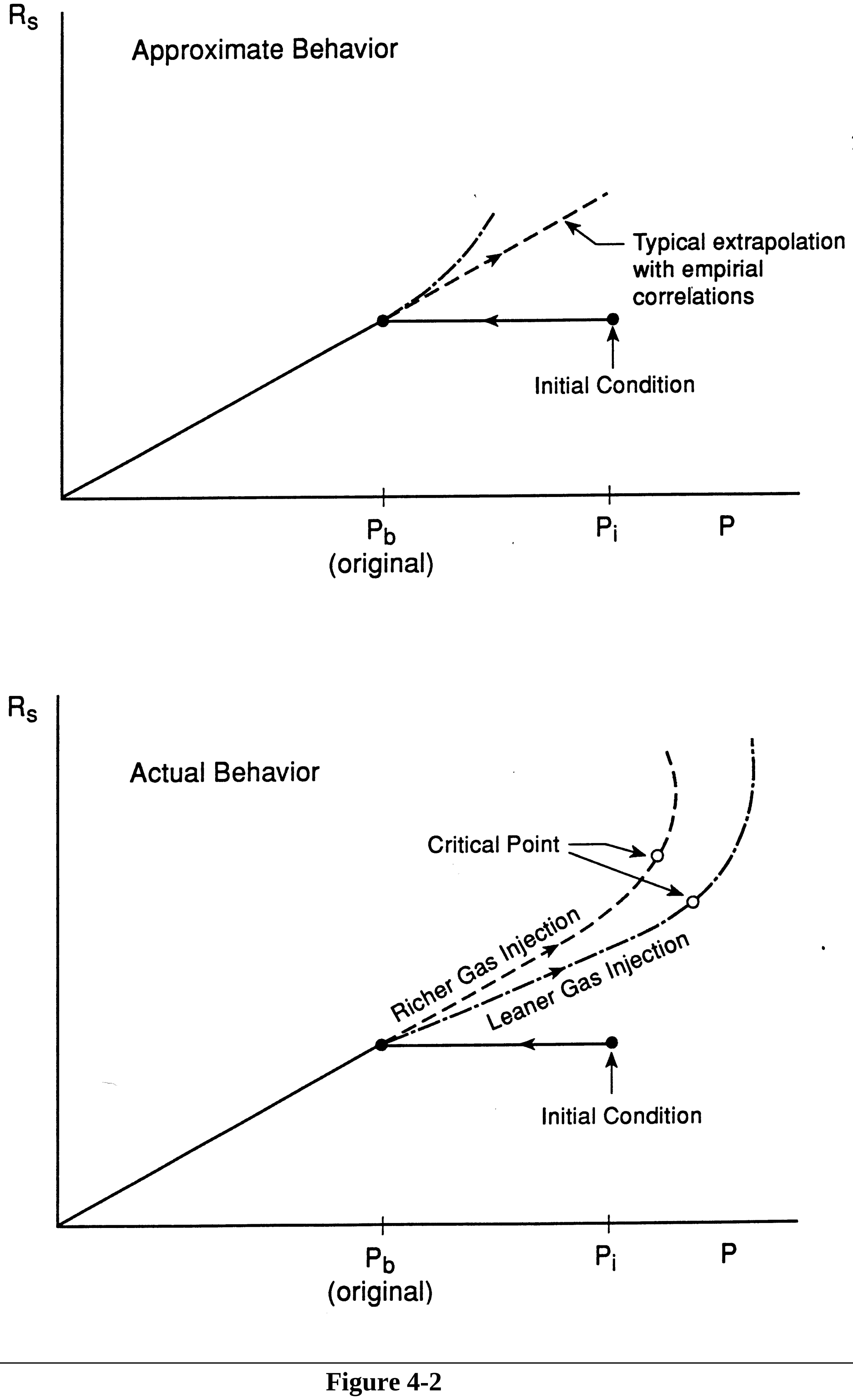

Rs
Approximate Behavior
Typical extrapolation with empirial correlations
Initial Condition
Pb (original)
Pi
P
Rs
Actual Behavior
Critical Point
Richer Gas Injection
Leaner Gas Injection
Initial Condition
Pb (original)
Pi
P

**Figure 4-2**

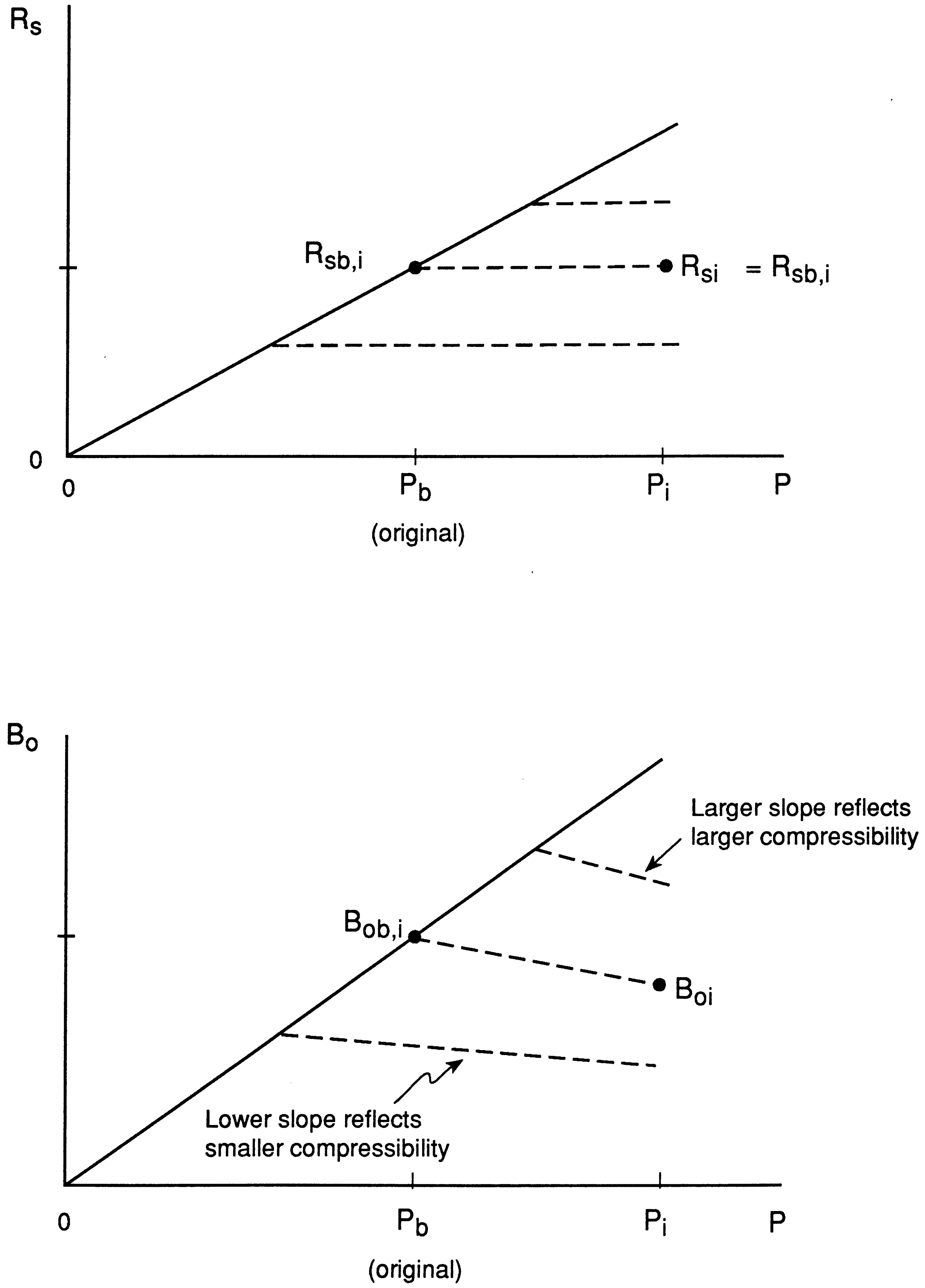

$R_s$
$R_{sb,i}$
$R_{si} = R_{sb,i}$
0
0
$P_b$
(original)
$P_i$
P
$B_o$
Larger slope reflects larger compressibility
$B_{ob,i}$
$B_{oi}$
Lower slope reflects smaller compressibility
0
$P_b$
(original)
$P_i$
P

Figure 4-3

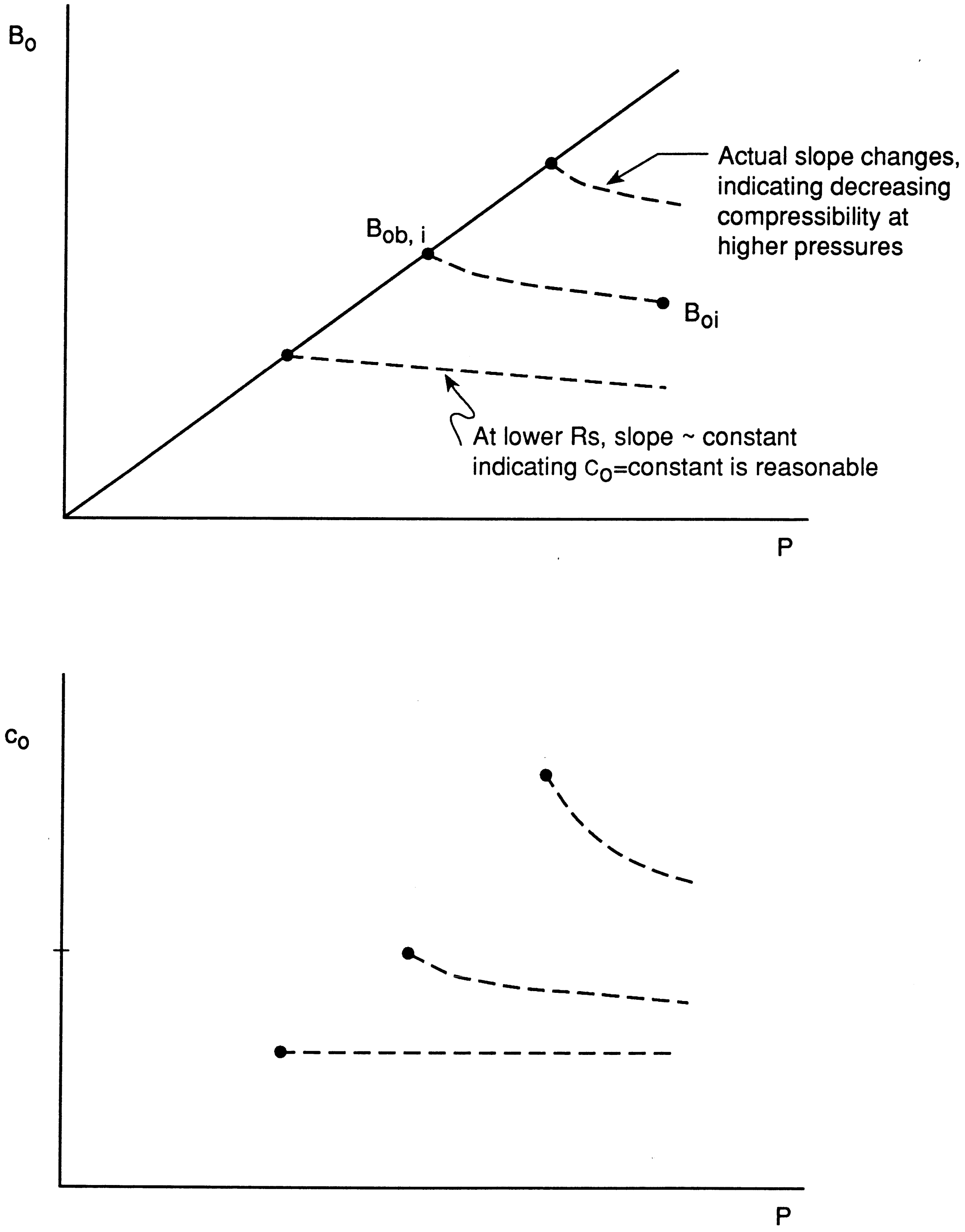
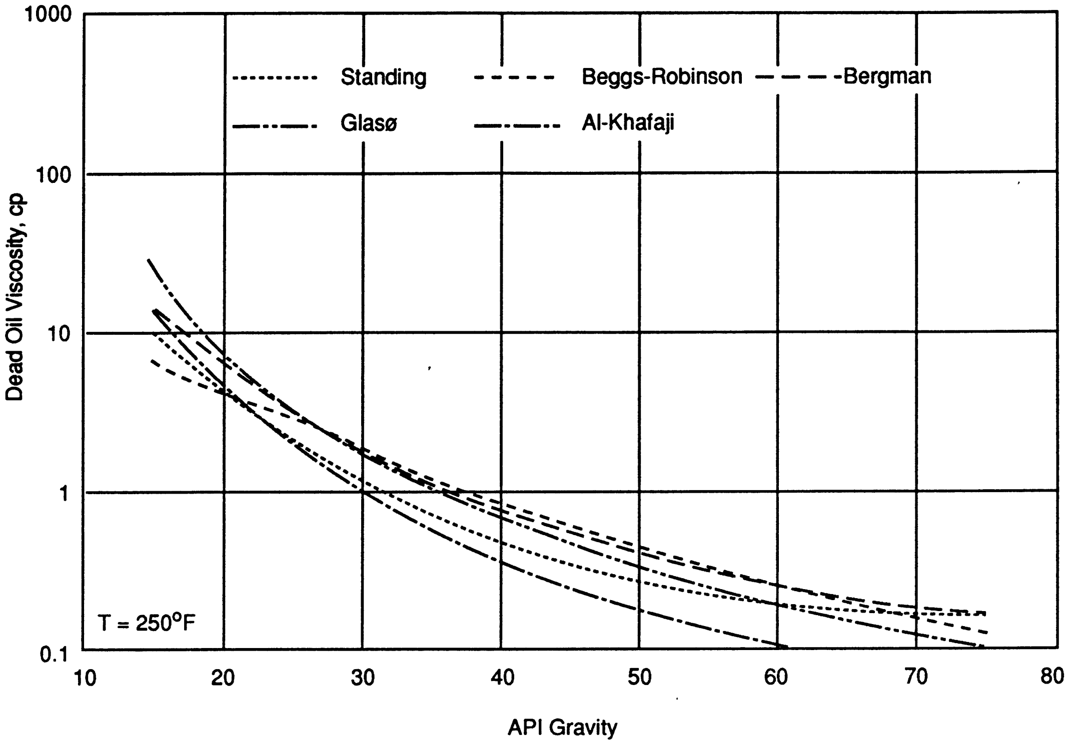
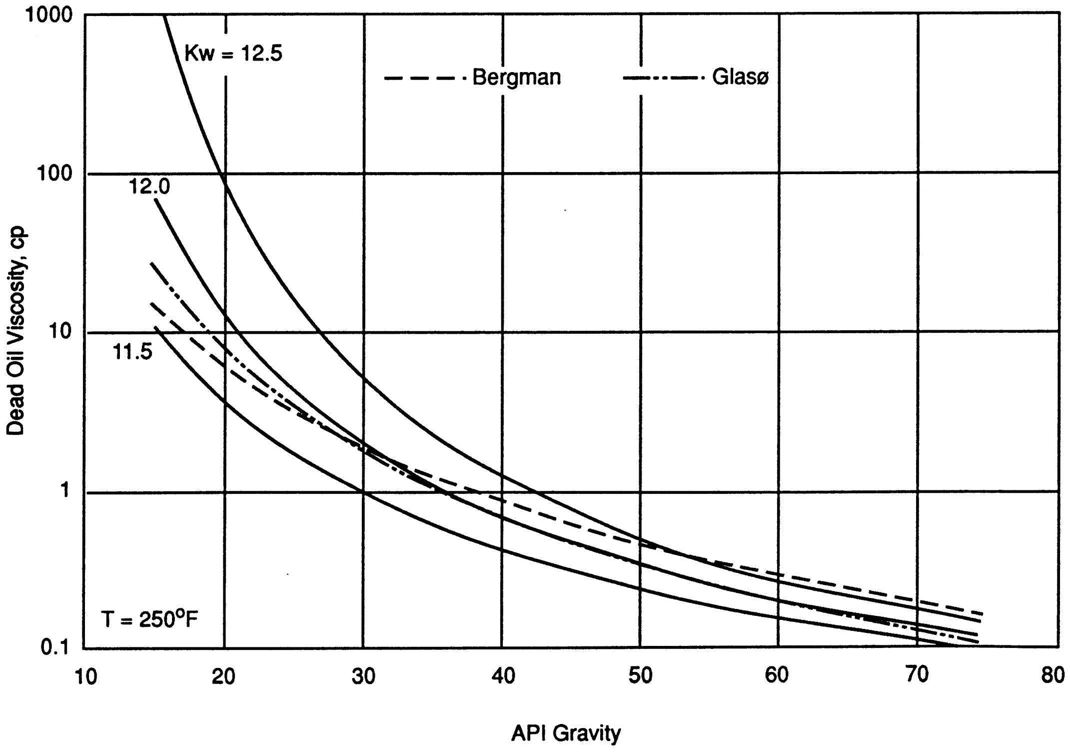

$B_o$
$B_{ob,i}$
Actual slope changes, indicating decreasing compressibility at higher pressures
$B_{oi}$
At lower Rs, slope ~ constant indicating $c_o$=constant is reasonable
P
$c_o$
P

Figure 4-4



1000
100
10
1
0.1
Dead Oil Viscosity, cp
Standing
Beggs-Robinson
Bergman
Glasø
Al-Khafaji
T = 250°F
10
20
30
40
50
60
70
80
API Gravity



1000
100
10
1
0.1
Dead Oil Viscosity, cp
Kw = 12.5
12.0
11.5
Bergman
Glasø
T = 250°F
10
20
30
40
50
60
70
80
API Gravity

Figure 4-5

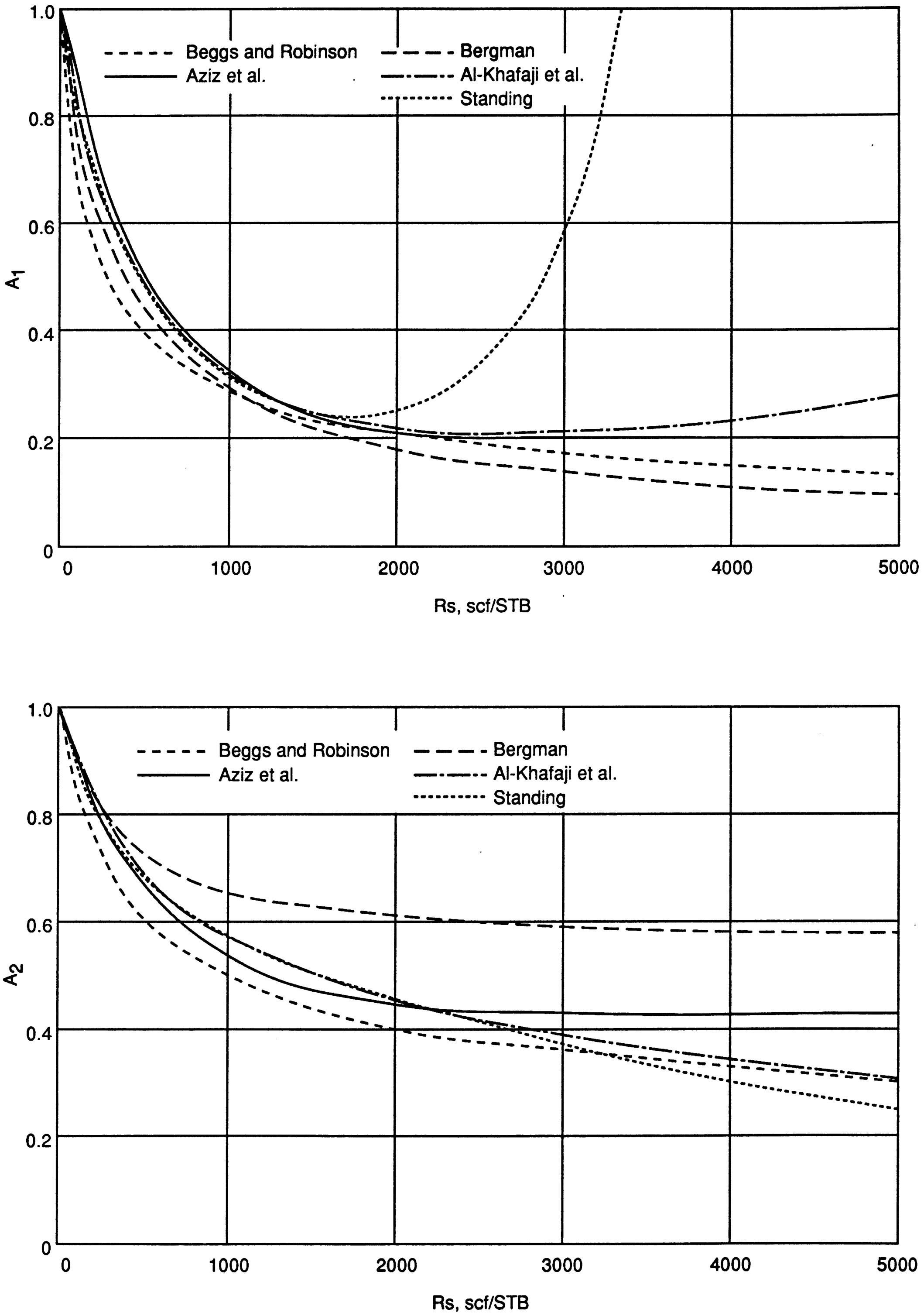

1.0
0.8
0.6
0.4
0.2
0
A1
0
1000
2000
3000
4000
5000
Rs, scf/STB
Beggs and Robinson
Aziz et al.
Bergman
Al-Khafaji et al.
Standing
1.0
0.8
0.6
0.4
0.2
0
A2
0
1000
2000
3000
4000
5000
Rs, scf/STB
Beggs and Robinson
Aziz et al.
Bergman
Al-Khafaji et al.
Standing

**Figure 4-6**

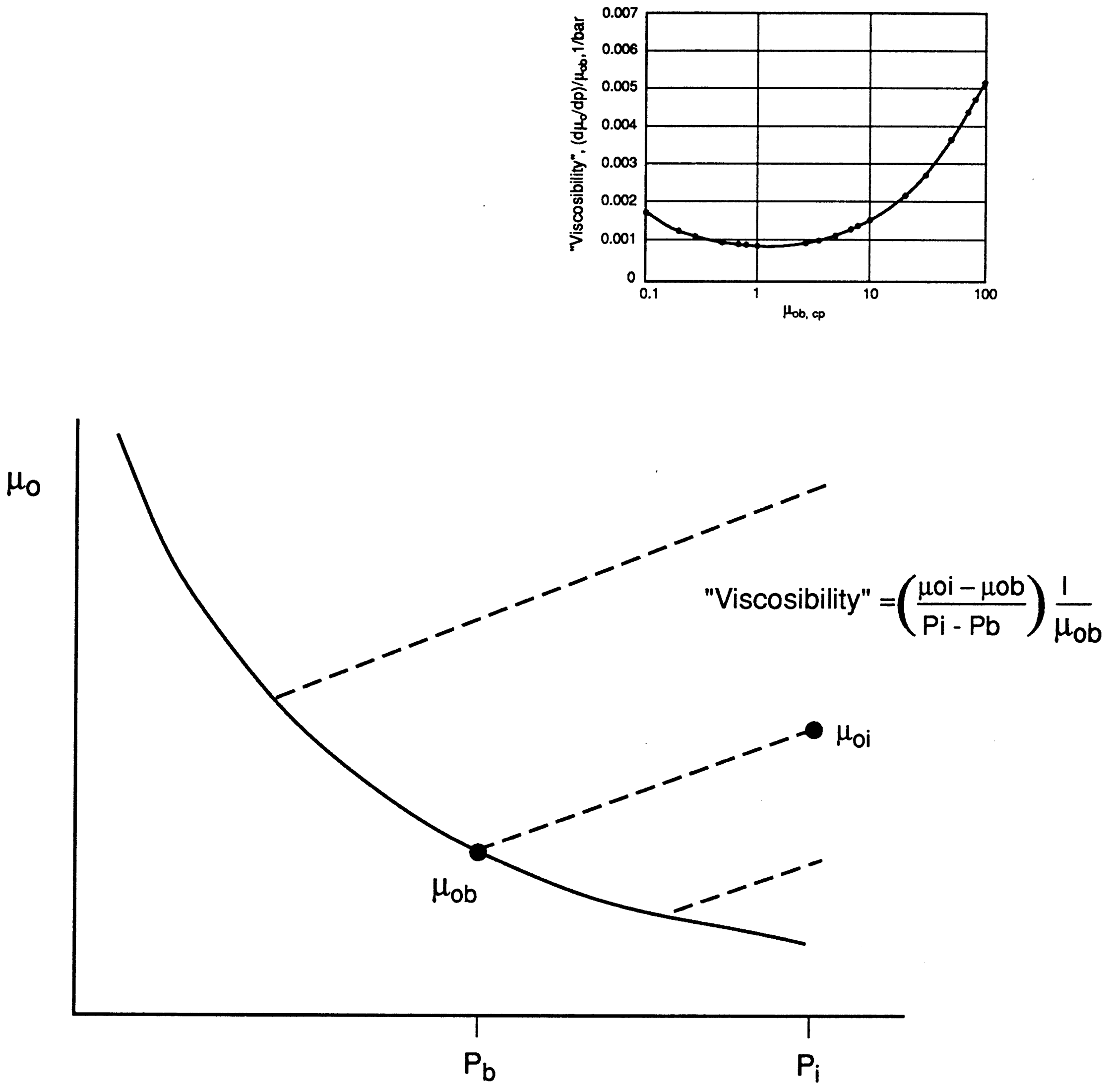

0.007
0.006
0.005
0.004
0.003
0.002
0.001
0
0.1
1
10
100
"Viscosibility", (dμo/dp)/μob, 1/bar
μob, cp
μo
"Viscosibility" = ((μoi − μob)/(Pi - Pb)) 1/μob
μoi
μob
Pb
Pi

**Figure 4-7**

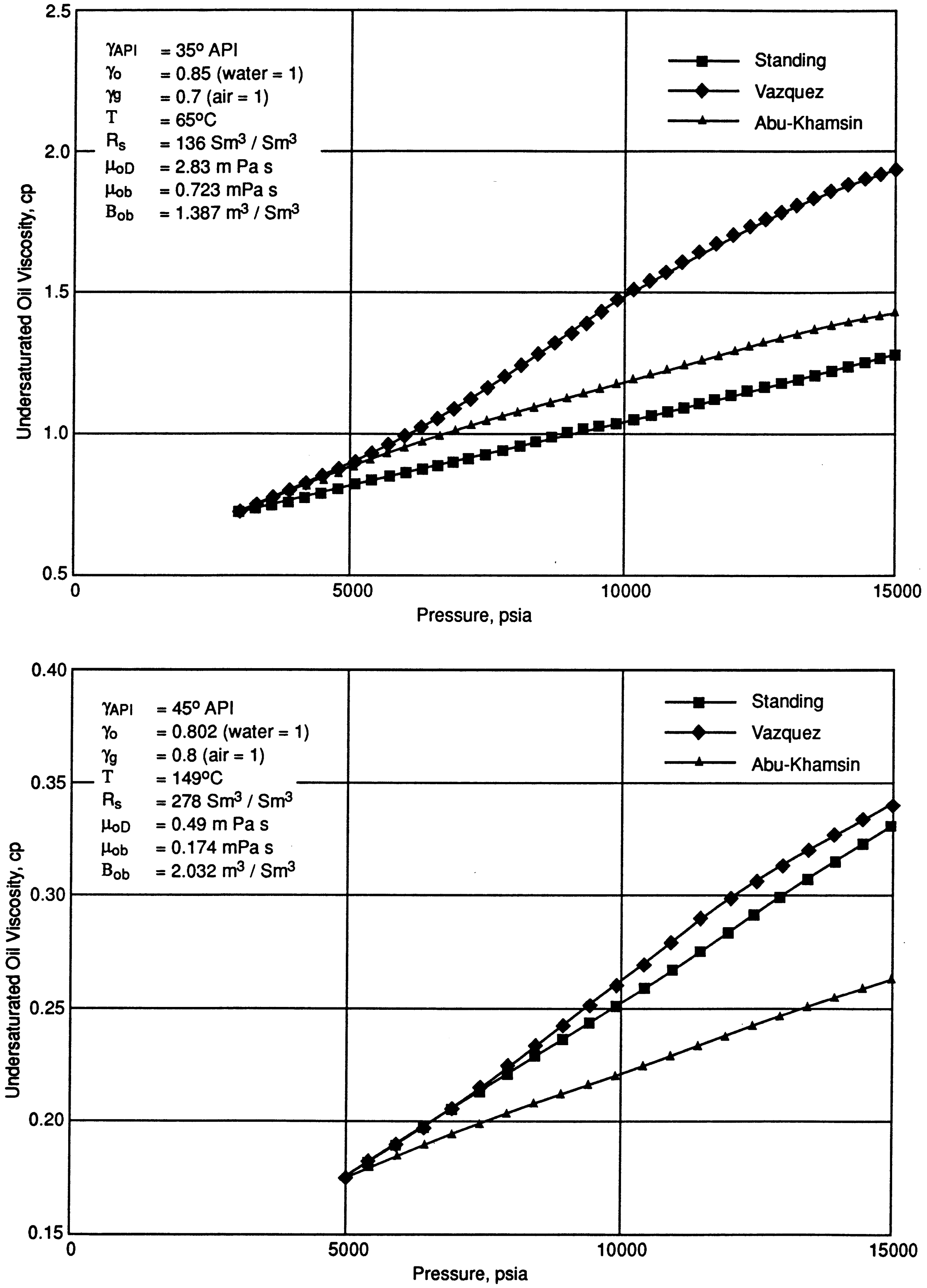

γAPI = 35° API
γo = 0.85 (water = 1)
γg = 0.7 (air = 1)
T = 65°C
Rs = 136 Sm3 / Sm3
μoD = 2.83 m Pa s
μob = 0.723 mPa s
Bob = 1.387 m3 / Sm3
Standing
Vazquez
Abu-Khamsin
2.5
2.0
1.5
1.0
0.5
0
5000
10000
15000
Undersaturated Oil Viscosity, cp
Pressure, psia
γAPI = 45° API
γo = 0.802 (water = 1)
γg = 0.8 (air = 1)
T = 149°C
Rs = 278 Sm3 / Sm3
μoD = 0.49 m Pa s
μob = 0.174 mPa s
Bob = 2.032 m3 / Sm3
Standing
Vazquez
Abu-Khamsin
0.40
0.35
0.30
0.25
0.20
0.15
0
5000
10000
15000
Undersaturated Oil Viscosity, cp
Pressure, psia

**Figure 4-8**

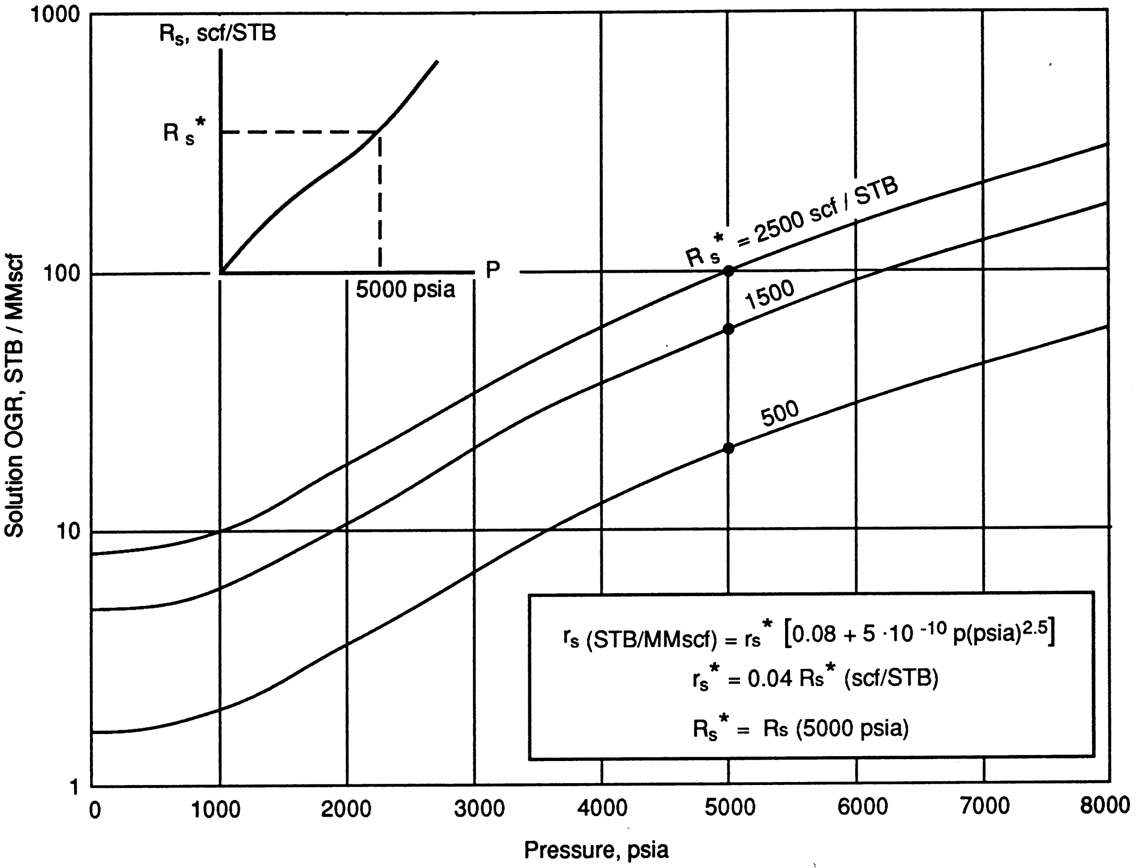

Rs, scf/STB
Rs*
5000 psia
P
Rs* = 2500 scf / STB
1500
500
rs (STB/MMscf) = rs* [0.08 + 5 ·10 -10 p(psia)2.5]
rs* = 0.04 Rs* (scf/STB)
Rs* = Rs (5000 psia)
Solution OGR, STB / MMscf
1000
100
10
1
0
1000
2000
3000
4000
5000
6000
7000
8000
Pressure, psia

Figure 4-9